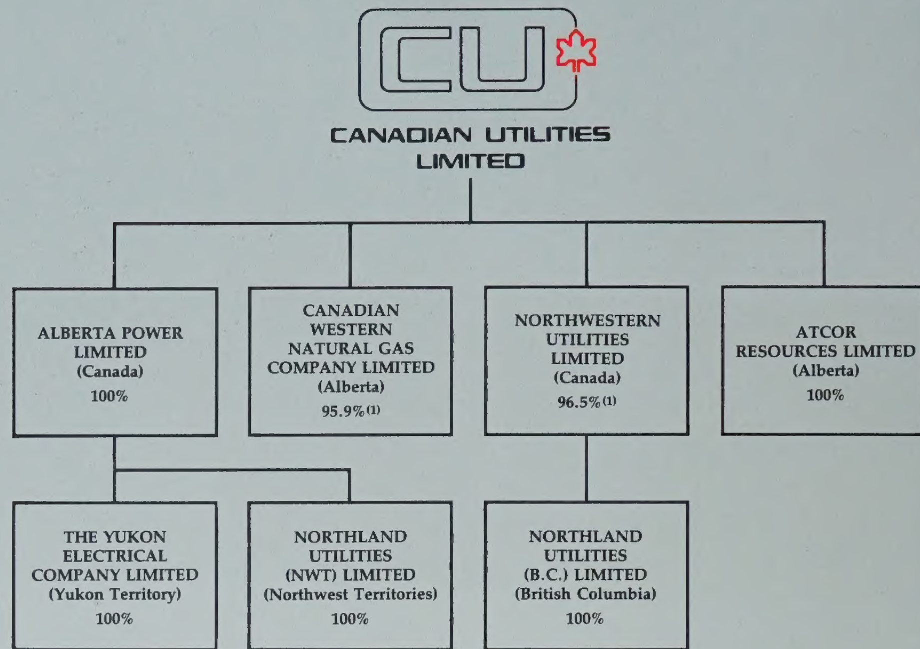
1985 ANNUAL REPORT · CANADIAN UTILITIES LIMITED

CORPORATE STRUCTURE



This chart shows the names of CU's operating subsidiaries, the jurisdictions in which they were organized and the percentages of their voting securities owned by CU.

Note 1: The minority interest is by way of voting non-participating preferred shares.

CORPORATE MISSION

Canadian Utilities Limited is an investor-owned company committed to expand in the business of generating, transmitting, distributing and selling electric power, and in the business of producing, transmitting, distributing and selling natural gas, while providing safe, dependable service at just and reasonable rates; and to aggressively pursue non-utility growth by seeking out and participating in energy and resource-related opportunities, while earning returns sufficient to attract and maintain the confidence of investors.

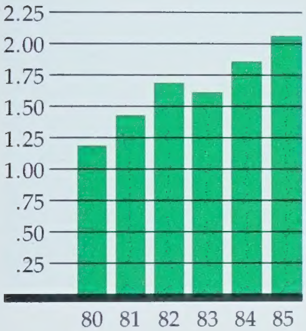
HIGHLIGHTS

	1985	1984	Increase (Decrease)
Revenues (thousands)			
Natural gas	$ **854,164**	$ 861,218	$ (7,054)
Electric	**323,903**	340,345	(16,442)
Non-utility			
Energy operations	**147,237**	162,203	(14,966)
Other	**632**	664	(32)
Total	$ **1,325,936**	$ 1,364,430	$(38,494)
Earnings attributable to shares* (thousands)	$ **111,949**	$ 101,405	$ 10,544
Earnings per share*	$ **2.07**	$ 1.87	$ .20
Equity per share*	$ **12.21**	$ 11.36	$ .85
Dividend per share*			
Annual	$ **1.22**	$ 1.08	$ .14
Fourth Quarter	$ **.32**	$ .30	$ .02
Shares* outstanding	**54,211,574**	54,211,574	

* Class A non-voting and Class B common shares

	1985	1984	Increase (Decrease)
Capital expenditures (thousands)	$ **235,618**	$ 242,478	$ (6,860)
Customers at year-end			
Natural gas	**601,794**	593,558	8,236
Electric	**147,124**	143,401	3,723

Earnings per Class A and Class B Share
(dollars)



Equity per Class A and Class B Share
(dollars)

CONTENTS

COVER

The front cover design is a computer graphic representation of energy. Inset is a photograph of a gas valve taken at the ATCOR Resources ethane extraction plant in Edmonton.

TO THE SHAREHOLDERS

Canadian Utilities Limited earnings attributable to Class A and Class B shares for the year ended December 31, 1985 were $111,949,000 ($2.07 per share) compared to $101,405,000 ($1.87 per share) for the previous year.

A number of positive factors contributed to the 10% increase in earnings, among them: the net effect of gas utility rate adjustments, increased electric utility sales, colder weather (the effects of which are described in the natural gas operations section of this report) and gains on the Company's investment in TransAlta Utilities Corporation. Earnings were reduced by a write-down of petroleum and natural gas assets by ATCOR Resources Limited, CU's non-utility subsidiary, and provisions for refunds to electric utility customers.

Revenues declined during the year to $1,325,936,000 from $1,364,430,000 in 1984, primarily because of the refunds to electric utility customers and reductions in gas utility rates due to reduced Federal energy taxes.

The Company's natural gas and electric utility operations continued to experience modest growth in customer numbers during the year. At the end of 1985, there were 601,794 natural gas customers, and 147,124 electric customers compared to 593,558 and 143,401 respectively a year earlier.

Total natural gas throughput (sales plus gas transported for others through the Company's pipelines) increased slightly during 1985 to 474.8 petajoules from 470.5 petajoules in 1984. Gas sales volumes declined 3%, while transportation volumes increased 8%.

Electric sales to retail customers increased 12% to 4,331 million kilowatt hours in 1985 from 3,882 million kilowatt hours in 1984. The demand for

electricity to operate oilfield extraction equipment accounted for much of the increase.

During the year, ATCOR recorded growth in its natural gas marketing and natural gas processing operations. A particularly encouraging development for ATCOR was the announcement by Gulf Resources Canada during 1985 of significant oil reserves — estimated at between 600 and 700 million barrels — at the Amauligak location in the Beaufort Sea. ATCOR has a 30% interest in AT&S Exploration Ltd. which, in turn, has a 6.2% interest in the Amauligak discovery with an option to increase its participation to 12.6%.

In December 1985, the Alberta Public Utilities Board (the Board) issued a final revenue requirement decision on the 1985 general rate application of Canadian Western Natural Gas Company Limited, CU's natural gas utility in southern Alberta. The decision allowed the utility to recover an additional $7.1 million of 1985 revenues and an additional $17.7 million of 1986 revenues. Northwestern Utilities Limited, the Company's northern Alberta natural gas utility, continued to charge interim rates which were approved by the Board in late 1984. A decision on Northwestern's general rate application is expected in 1986.

In December 1985, another Board decision set 1984 and 1985 revenue requirements for Alberta Power Limited, CU's major electric utility subsidiary. In this decision, the Board directed Alberta Power to refund $13.3 million of 1984 revenues and $29.1 million of 1985 revenues. (Additional details concerning regulatory activity are included in the utility operations sections of this report.)

In June 1985, the Alberta Cabinet upheld an earlier decision by the Energy Resources Conservation Board to allow the Sheerness Generating Station in southeastern Alberta to proceed on a revised schedule recommended by the Company to accommodate slower growth in electrical energy demand than had previously been forecast. Accordingly, Sheerness Unit 1 began commercial service in January 1986 with Sheerness Unit 2 now planned to follow in the fall of 1990. Sheerness is a joint project of Alberta Power Limited and TransAlta Utilities Corporation.

Taking advantage of the opportunity to reduce its financing costs, the Company, in October 1985, issued $125 million of 7.80% Cumulative Redeemable Second Preferred Shares Series K and applied the proceeds principally to the redemption of the 9.24% Cumulative Redeemable Second Preferred Shares Series B and the 10.24% Cumulative Redeemable Second Preferred Shares Series D. Early in 1986, the Company also announced its intention to redeem the 10.12% Cumulative Redeemable Second Preferred Shares Series E.

In October 1985, the Board of Directors declared a fourth quarter dividend of 32¢ per Class A and Class B share, up from 30¢ in the previous 4 quarters. The common share dividend has been increased 15 times in the past 14 years.

The March 1985 Western Accord agreed to by the Federal Government and the Province of Alberta provided the prospect of significant increases in netbacks to the oil and gas industry over the next 5 years. This, in turn, was expected to generate increased oil and gas investment in Alberta. In view of the recent reductions in world oil prices, future trends

Chairman of the Board and Chief Executive Officer R. D. Southern (seated) and J. D. Wood, President and Chief Operating Officer.

in Alberta oil and gas prices will have to be clarified before Alberta's overall economic outlook can be more accurately assessed.

Since the publication of the Company's 1984 annual report, the following senior management appointments have been announced: C. S. Richardson, in addition to his position as Deputy Chairman, became Chief Financial Officer; H. N. Bottomley, formerly Vice-President and Controller, was appointed Vice-President Finance and Administration; and D. B. Mitchell, previously Vice-President Human Resources, became Vice-President Human Resources and Corporate Services.

The Company's considerable success in 1985 was achieved largely because employees at all levels of the organization worked with energy, skill and creativity to reach demanding goals. The directors extend their deepest appreciation to employees for their outstanding efforts. The directors are also grateful to customers for their continuing support and to suppliers for their invaluable products and services.

On behalf of the Board of Directors,

R. D. Southern,
Chairman and
Chief Executive Officer

J. D. Wood
President and
Chief Operating Officer

February 28, 1986

UTILITY OPERATIONS

NATURAL GAS OPERATIONS

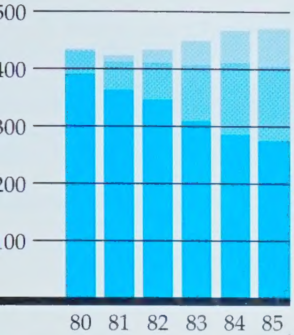
Canadian Utilities' natural gas operations are carried out by two utilities, Canadian Western Natural Gas Company Limited, which serves southern Alberta including Calgary and Lethbridge, and Northwestern Utilities Limited, which serves north-central Alberta including Edmonton, Red Deer, Fort McMurray, Grande Prairie, Camrose and Lloydminster. Northwestern Utilities' subsidiary, Northland Utilities (B.C.) Limited, serves Dawson Creek and district and the community of Tumbler Ridge in northeastern British Columbia.

Plastic pipe is used for an extension to Canadian Western's distribution system in south Calgary. This and other capital additions to serve natural gas customers totalled $69.0 million in 1985.

At the end of 1985 the Company's natural gas utilities were serving 601,794 customers, up 1.4% over the previous year.

Earnings attributable to Class A and Class B shares from natural gas operations were $52.4 million compared to $34.2 million in 1984. Weather favourably affected 1985 earnings by $9.8 million due to the combined effect of higher sales resulting from a colder than normal December 1984, a portion of which was billed in January 1985, and reduced gas supply costs as a result of warmer weather in December 1985. Other major factors favourably affecting earnings were: revenues allowed for the year 1984 but billed in 1985, purchase of lower priced natural gas on the spot market, income tax reassessments for the years 1981 through 1984 and cost control programs. A short-term demand for petrochemical, refinery and fertilizer products from Northwestern Utilities' transportation customers also contributed to the increased earnings.

Natural Gas System Throughput
(petajoules)



Natural Gas Revenues
(millions of dollars)

Earnings Attributable to Class A and Class B Shares
(millions of dollars)

Two additional salt caverns were brought into service by Northwestern Utilities in 1985, doubling the number of these natural gas storage reservoirs near Fort Saskatchewan. A fifth cavern will be added in 1986.

Natural Gas Throughput

Total system throughput rose during 1985 to 474.8 petajoules from 470.5 petajoules in the previous year. A decline of 10.0 petajoules in sales was more than offset by a 14.3 petajoule increase in transportation volumes. The sales decline is attributable largely to the loss of 2 oil refineries as sales customers and reduced sales to a fertilizer plant and sugar refinery.

CU's natural gas utilities transport gas within Alberta for exporting companies and for industrial and other customers who have contracted for their gas supplies directly with brokers or producers. The table on page 8 shows natural gas sales to various categories of customers, plus natural gas transported for exporting companies and industrial customers.

The homemaking services available through the natural gas utilities' Blue Flame Kitchens in Calgary and Edmonton continue to be popular with natural gas users.

Natural Gas Revenues, Expenses and Taxes

Consolidated natural gas revenues for 1985 were $854.2 million compared to $861.2 million in 1984. Increases due to weather, customer growth and rate adjustments were outweighed by reductions in Federal taxes and the substitution

Natural Gas Sales and Transportation

	Terajoules	% of Total
Sales		
Industrial	73,901	15.6
Commercial	97,244	20.5
Residential	94,421	19.9
Other	8,668	1.8
	274,234	**57.8**
Transportation	130,857	27.5
	405,091	**85.3**
Sales and transportation — affiliates	69,766	14.7
Total system throughput	**474,857**	**100.0**

of transportation service for industrial sales.

Total operating expenses, which include the cost of natural gas supply, operations, maintenance, depreciation, taxes other than income and income taxes were down $27.6 million from 1984. Natural gas supply, the largest expense item, was down $38 million to $479.3 million.

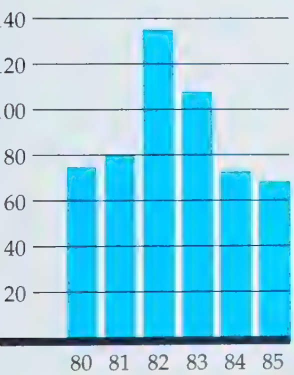
During 1985, the Federal Government began dismantling the National Energy Program. The Canadian Ownership Special Taxation was removed on June 1, 1985 and a program was introduced to phase out the Petroleum and Gas Revenue Tax. On October 31, 1985, the Natural Gas Agreement between the Federal Government and producing provinces was announced providing for the deregulation of natural gas pricing. By November 1, 1986, the price of gas will be set by the market rather than by government administered pricing.

Market-oriented pricing is expected to have little impact on rates charged to residential, commercial and small industrial customers because the Alberta Natural Gas Rebates Act already shields these customers from the cost of gas above 65% of the Alberta Border Price and market-oriented prices are not expected to fall below that price. The Act has been extended to March 31, 1988.

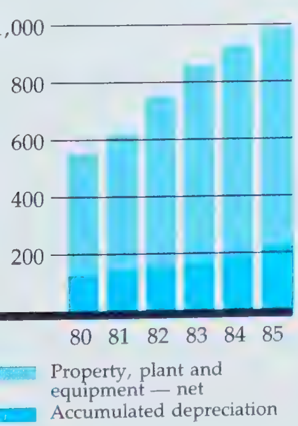
A control valve is installed at Northwestern's salt cavern project site 30 kilometres northeast of Edmonton.

Natural Gas Customers
(thousands)

Capital Expenditures
(millions of dollars)



Property, Plant and Equipment
(millions of dollars)



A 54-kilometre natural gas transmission line from Taber to Lethbridge was completed last summer, replacing a line built in 1912.

Regulatory Activity

In April 1985, Canadian Western filed an application with the Alberta Public Utilities Board (the Board) to recover projected shortfalls in revenue for 1985 and 1986. Following examination in July and August of Canadian Western's revenue requirements the Board approved an interim refundable rate increase, effective November 1, 1985. In December 1985, the Board issued its final decision on Phase I of the application adjusting upwards the increase in allowed 1985 revenues to $7.1 million and the increase in allowed 1986 revenues to $17.7 million. The 1985 rate increase has been recognized in reported revenues; $3.7 million will be collected in 1986. The Board-approved revenues for 1986 will be collected in 1986. A decision on final rates is expected during 1986.

In May 1984, Northwestern filed an application with the Alberta Public Utilities Board to recover projected shortfalls in revenue for 1984 and 1985. The Board approved an interim refundable rate increase, effective November 1, 1984 which allowed Northwestern to collect $10.0 million of its 1984 revenue shortfall during the period November 1, 1984 to June 30, 1985 and $25.0 million of the 1985 revenue shortfall during 1985. A final decision on Northwestern's

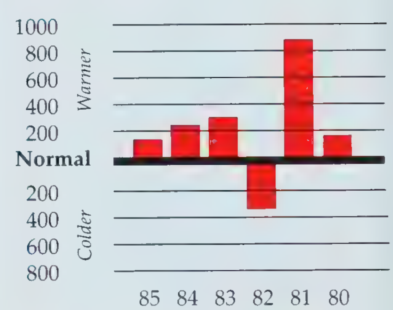
Gas Operations Earnings Contribution

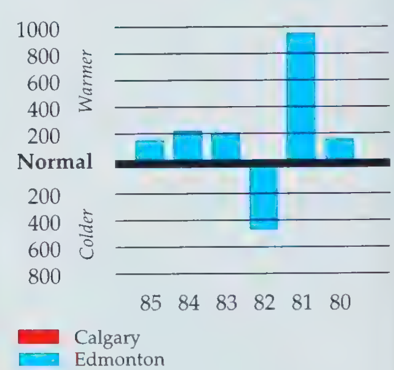
	1985	1984	1983	1982	1981	1980	Annual Growth Rate 1980-85
			($ Millions)				%
Natural gas revenues	**854.2**	861.2	928.4	959.1	779.2	581.7	8.0
Operating expenses							
Natural gas supply	**479.3**	517.3	512.6	444.8	442.2	405.8	3.4
Operation and maintenance	**120.2**	117.1	114.2	107.6	86.4	73.3	10.4
Taxes — other than income	**81.5**	97.9	207.3	306.2	185.6	47.1	11.6
Taxes — income	**57.4**	36.4	24.2	21.8	9.3	7.6	49.8
Depreciation and depletion	**25.6**	22.9	17.2	17.1	13.9	11.9	16.6
	764.0	791.6	875.5	897.5	737.4	545.7	7.0
	90.2	69.6	52.9	61.6	41.8	36.0	20.2
Other deductions — net	**37.8**	35.4	26.7	28.6	20.3	18.4	15.5
Earnings attributable to Class A and Class B shares	**52.4**	34.2	26.2	33.0	21.5	17.6	24.4
Mid-year common equity investment	**204.4**	183.2	171.8	145.2	117.9	109.2	13.4

application is also expected during 1986.

On August 1, 1985, the British Columbia Utilities Commission approved an increase to Northland Utilities (B.C.) Limited rates following an increase in the wholesale price of natural gas.

DEGREE DAYS





DEGREE DAYS: The number of degrees by which daily mean temperature falls below 18 degrees C. One degree day is counted for each degree of deficiency for each day on which such a deficiency occurs. For example, if the mean temperature for a day was 10 degrees C, then there are 8 degree days during the 24-hour period.

Construction Projects

Natural gas utility capital additions to provide for customer growth and to meet the needs of its existing customers were $69.0 million. Net property, plant and equipment required to serve customers increased to $769.4 million at year-end.

Canadian Western completed 54 kilometres of 323.9 mm transmission line between Lethbridge and Taber at a total cost of $7.8 million replacing a line built in 1912. In a pioneering effort, Canadian Western became the first pipeline installer to use a plowing technique for laying distribution lines across a major river. The cost is one-third that of the conventional trenching method.

Northwestern commissioned 2 additional salt caverns near Fort Saskatchewan in the County of Strathcona. Four caverns and related gas handling facilities are now available to meet customers' peak demand requirements. The fifth cavern will be completed in 1986. Expenditures on these facilities during 1985 amounted to $3.9 million. The caverns provide the most cost effective method of meeting current peaking requirements.

In addition, Northwestern installed compressor stations at Corbett Creek and Judy Creek northwest of Edmonton at a combined cost of $3.0 million. The compressors will permit pipeline capacity to be increased enabling Northwestern to fulfill new transportation agreements to move natural gas to the Judy Creek and Swan Hills areas.

Natural gas operations continued to exercise cost control measures introduced in previous years. Since year-end 1983, Canadian Western and Northwestern have added more than 21,000 customers, while the number of employees in 1985 were lower than in 1983.

Two-year agreements were signed with the natural gas utilities' employee associations early in 1985 providing the equivalent of a 3% pay raise for permanent employees in 1985 and including provision to negotiate salaries for 1986. Agreement has not yet been reached on 1986 salaries.

The natural gas utilities continued their program of converting company vehicles to run on compressed natural gas fuel. In the Vegreville district, Northwestern Utilities' vehicles refuel at this Nova Corporation station.

Unit 1 of the Sheerness Generating Station near Hanna, Alberta went into commercial service January 1, 1986. Unit 2 is scheduled to follow in 1990.

ELECTRIC POWER OPERATIONS

Canadian Utilities' major electric utility, Alberta Power Limited, serves 321 communities in east-central and northern Alberta, including Fort McMurray, Grande Prairie, Lloydminster, Drumheller and Peace River, and 2 communities in Saskatchewan.

Alberta Power's subsidiary companies, The Yukon Electrical Company Limited and Northland Utilities (NWT) Limited, serve 18 communities in the Yukon, one community in British Columbia and 6 communities in the Northwest Territories. Another subsidiary, Yukon Hydro Company Limited, operates 2 small hydroelectric plants in the Yukon.

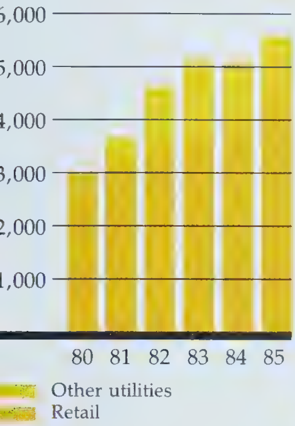
Energy sales to retail customers in 1985 increased by 11.6% to 4,331 million kilowatt hours. In addition, 1,171 million kilowatt hours were sold to the City of Edmonton under a unit power agreement and 119 million kilowatt hours were sold to Edmonton Power and TransAlta Utilities under a Province-wide system of economic dispatch.

During 1985, 3,723 retail customers, including several major oil and gas customer loads, were added, bringing the year-end total to 147,124. Included in this number were 26,471 farm customers of whom 16,360 are members of 98 rural electrification associations. During 1985, 3 rural electrification associations comprising 400 members voted to sell their distribution systems to Alberta Power.

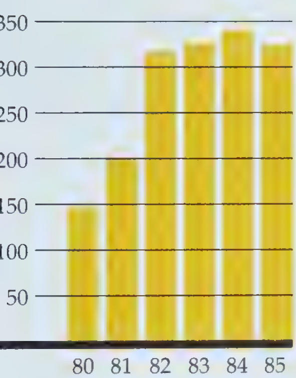
The peak load created by Alberta Power's retail customers increased to 844 megawatts in 1985 from 741 megawatts the previous year.

The following table shows 1985 electric sales to the various customer groups (excluding sales to other utilities):

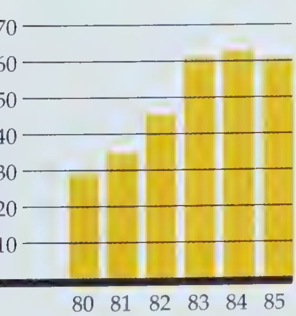
Electric Sales
(millions of kilowatt hours)



Electric Revenues
(millions of dollars)

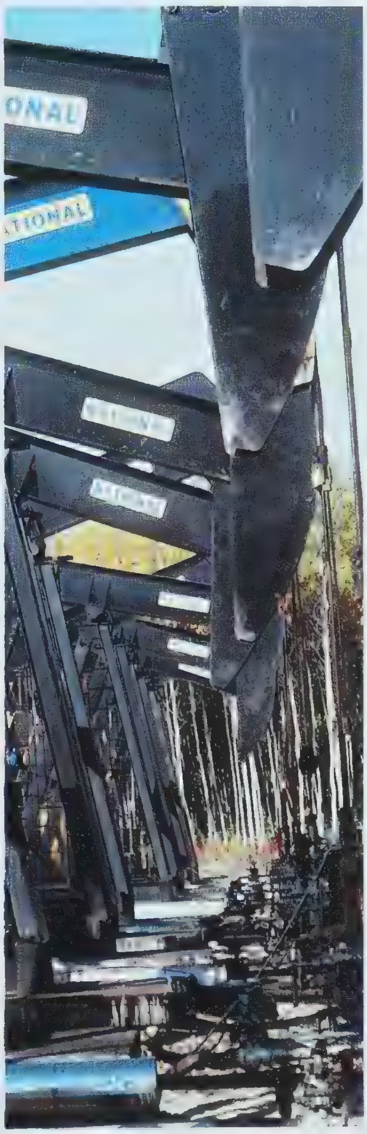


Earnings Attributable to Class A and Class B Shares
(millions of dollars)



Electric Power Sales

	Thousands of Kilowatt Hours	% of Total
Industrial	2,447,843	56.5
Commercial	763,738	17.6
Residential	691,068	16.0
Other	428,174	9.9
	4,330,823	**100.0**



Heavy oil recovery projects in the Cold Lake and Lloydminster areas contributed to the increased demand for electricity in the Alberta Power service area.

The first unit of the Sheerness Generating Station commenced regular operation on January 1, 1986. The second unit is scheduled to begin operation in 1990. The station, and the associated coal-handling facilities, are jointly owned with TransAlta Utilities, with Alberta Power serving as managing partner.

The pre-investment study phase of the proposed hydroelectric project on the Slave River ended during 1985 when the study group — the Government of Alberta, Alberta Power and TransAlta Utilities — concluded the project was not feasible at this time.

Along with other companies and individuals in its service area who were affected by the recession, Alberta Power maintained restraint measures, first implemented during 1982, on both operating and capital expenditures.

Hiring and overtime were restricted with the result that, although the number of customers increased by 2.6%, and energy sales by 9.21%, permanent staff declined in number.

An agreement was reached with the Alberta Power Employee Association under which members of the association received no salary increase for 1986, but rather received a 3.5% lump-sum cash payment. The current working agreement with the employee association remains in force until the end of 1986.

Earnings attributable to Class A and Class B shares from electric operations were $60.8 million compared to $62.9 million in the previous year.

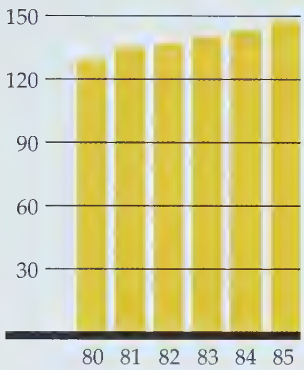
Regulatory Activity

On May 17, 1985, the Energy Resources Conservation Board (ERCB) issued its report on the timing of generating plant additions within Alberta. The ERCB accepted the proposal put forward by Alberta Power that the first unit of the Sheerness plant, jointly owned by Alberta Power and TransAlta Utilities, be commissioned as scheduled in January 1986, and that the second unit be deferred to 1990. The first unit of Edmonton Power's Genesee plant will be commissioned in 1989, with the second following in 1991. The ERCB recommendations were approved by the Provincial Cabinet.

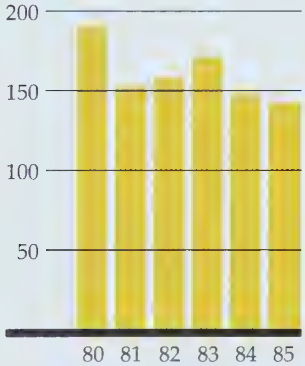
Two decisions affecting Alberta Power were issued during 1985 by the Alberta Public Utilities Board (the Board) in connection with the Board-initiated hearing into the company's revenue requirements and rates for the 1984 and 1985 test years.

On July 8, the Board directed the company to initiate a credit rider reducing the bills of all customers by 4.25% on an interim refundable

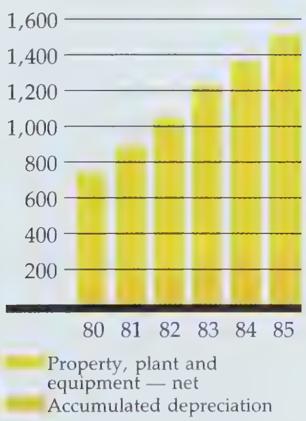
Electric Customers
(thousands)



Capital Expenditures
(millions of dollars)



Property, Plant and Equipment
(millions of dollars)



Electric Operations Earnings Contribution

	1985	1984	1983	1982	1981	1980	Annual Growth Rate 1980-85
			($ Millions)				%
Electric revenues	**323.9**	340.3	327.2	316.3	201.7	149.8	16.7
Operating expenses							
Operation and maintenance	**137.2**	128.7	122.3	131.4	93.7	74.4	13.0
Taxes — other than income	**12.6**	12.5	12.3	9.9	7.2	5.1	19.8
Taxes — income	**46.2**	60.4	58.2	56.0	17.8	11.8	31.4
Depreciation and depletion	**30.5**	34.1	31.8	29.8	20.9	16.0	13.8
	226.5	235.7	224.6	227.1	139.6	107.3	16.1
	97.4	104.6	102.6	89.2	62.1	42.5	18.0
Other deductions — net	**36.6**	41.7	41.3	43.6	27.2	13.2	22.6
Earnings attributable to Class A and Class B shares	**60.8**	62.9	61.3	45.6	34.9	29.3	15.7
Mid-year common equity investment	**350.4**	323.7	293.7	243.1	198.5	181.3	14.1

basis for all electricity consumed on or after July 1.

On December 20, the Board issued its final decision on the revenue requirement phase of its hearing. It found that the rates established for the company in 1982 had resulted in unexpectedly high revenue, primarily as a result of a significant increase in retail electric energy sales due to improvements in the economy. At the same time, productivity improvements and Board-ordered adjustments to operating costs, depreciation and income taxes reduced the overall expenses and revenue requirements.

The Board maintained Alberta Power's allowable rate of return on common

The Yukon Electrical Company serves 18 communities in the Territory. This hydro plant is one of two operated by another Alberta Power subsidiary, Yukon Hydro Company near Whitehorse.

An Alberta Power "hotline" crew at Grande Prairie is able to make line repairs without de-energizing the line, thus avoiding interruption of service to customers in the area.

equity at 17% for 1984, and established a 14.75% level for 1985.

The Board ruled that in 1984 Alberta Power's revenues exceeded requirements by $13.3 million and that 1985 forecast revenues were expected to exceed requirements by $29.1 million. The Board directed Alberta Power to file by February 1, 1986 a plan to refund to customers the revenue which exceeded requirements. About $6 million of the total amount had already been refunded by year-end, as a result of the July 8 interim refund order.

After recording the total impact of this decision, Alberta Power's consolidated earnings declined to $60.8 million in 1985 from $62.9 million in 1984. Higher-than-expected energy sales, primarily to commercial and industrial customers, helped to offset the impact on earnings of the Board decision. In addition, a portion of the 1985 refund relates to Board-ordered depreciation adjustments and the company reduced its depreciation expense accordingly.

At year-end, the Board had not established a date for the next phase of the hearing in which Alberta Power is seeking approval for a rate redesign.

Alberta Power also made applications to the Board for prices for the sale of energy to the Alberta Electric Energy Marketing Agency covering 1985 and 1986. The company will be required to file actual figures for each of these years with resulting adjustments to be incorporated into the marketing agency price for 1987 and 1988 respectively.

Construction Projects

Alberta Power's additions to property, plant and equipment during the year totalled $142.0 million. The largest single amount —$78.9 million — was spent on the Sheerness Generating Station.

Expenditures on transmission projects during the year totalled $26.5 million. Major projects included a static var compensator at Bonnyville, a third phase of the Anderson sub-station, and the construction of 151 kilometres of 144-kilovolt line.

Expenditures on transmission projects are expected to triple in 1986 as Alberta Power responds to the increased needs in its service area, particularly from those engaged in resource development in northwest Alberta, the Cold Lake area and Fort

Power from the Sheerness Generating Station is now feeding the Alberta interconnected system.

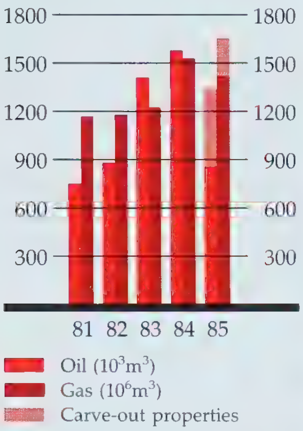
McMurray. Falling oil prices, however, could alter the Province's economic prospects and require changes in capital expenditure plans.

Projects currently planned or underway involve 377 kilometres of double-circuit, 240-kilovolt line, 265 kilometres of single-circuit, 240-kilovolt line and 115 kilometres of 144-kilovolt line.

NON-UTILITY OPERATIONS

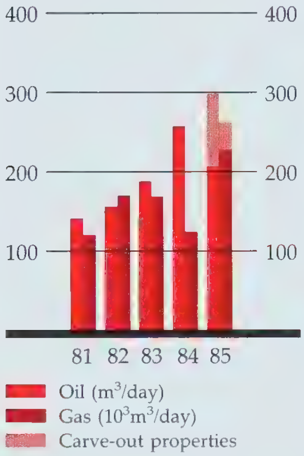
Reserves

(gross before royalties)
(proven and probable)



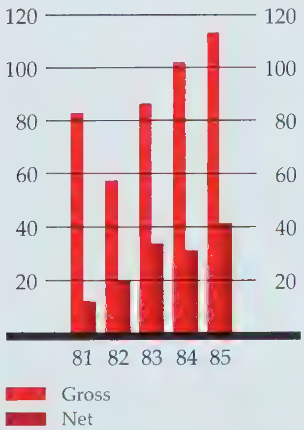
Production

(gross before royalties)



Drilling Activity

(number of wells drilled)



ATCOR Resources conducted an extensive oil and gas exploration and development program during 1985. The photo shows an ATCOR heavy oil development well near Maidstone, Saskatchewan.

The year under review was one of significant change for the oil industry. Most notably, it marked the beginning of a new era of price deregulation with the announcement of the Western Accord in March and the Agreement on Natural Gas Markets and Prices in October. In addition, a number of Federal oil and gas taxes and charges were eliminated under the Western Accord. Termination of the Petroleum Incentives Program and the phasing out of the Petroleum and Natural Gas Revenue Tax (PGRT), effectively rescinded the National Energy Program of 1980.

However, deregulation of oil and gas prices came at a time of falling world oil prices and generally depressed markets for natural gas. While the new tax regime introduced by the Western Accord was long overdue, the impact of deregulation had a detrimental impact on small and medium size oil and gas producers. Prices for a significant portion of their oil production had been regulated at levels which were above the world price. Since June 1, when the deregulation of oil prices came into effect, prices received by these producers for oil discovered since 1974 have fallen dramatically. The impact of lower oil prices was offset to some extent by a gradual phasing out of PGRT on existing production and the elimination of PGRT on production from new discoveries after April 1, 1985. In addition, the Government of Alberta has offered additional incentives to producers, including a 12-month royalty holiday and an

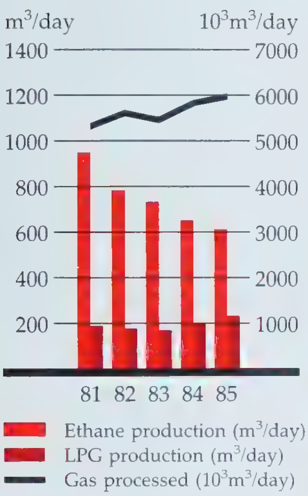
increase in the Alberta Royalty Tax Credit to a maximum of $3 million.

The long-term benefits to the industry of deregulation, as well as the introduction of a new tax regime directed at taxing profits rather than revenues, is considered to be very positive. Having taken steps to return the oil industry to an equal status with other industries in Canada, it is hoped both governments will remain on the sidelines, allowing energy prices and investment decisions to be determined in the marketplace.

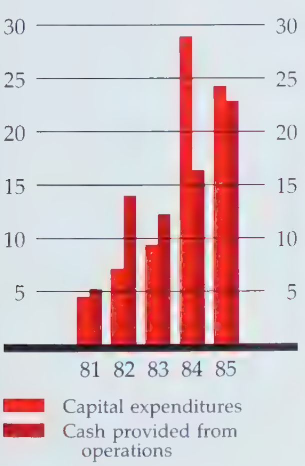
Financial Highlights

Revenues and operating income for ATCOR Resources Limited, CU's non-utility subsidiary, were down slightly from 1984 as a result of lower oil and gas production associated with the sale for $17 million of certain working interests in oil and gas reserves (the carve-out) to an affiliated company and a general decline in oil prices during the latter part of the year. ATCOR's crude oil prices fell an average of 14% between June 1 and December 31. A write-down of petroleum and natural gas assets during the year caused operating income to decline by a further $17.7 million. The write-down reflects ATCOR's policy of limiting the book value of oil and gas properties to the aggregate of the estimated

Gas Processing



Capital Expenditures and Cash Provided from Operations
(millions of dollars)



A major extension to the Dome/ATCOR ethane extraction plant at Edmonton was completed in 1985 providing additional plant capacity.

realizable value of future net income from proven oil and gas reserves and the lower of cost or fair value of undeveloped acreage.

Exploration and Production

Exploration activities in 1985 were concentrated primarily in Alberta. ATCOR participated in the drilling of 113 gross wells (41 net) with a success ratio of 20% for exploration wells and 70% for development wells.

Net capital expenditures on exploration and production activities, excluding expenditures on acquisitions and investments in AT&S, were $15.7 million, down 4% from the previous year. An additional $3.6 million was invested in AT&S through the purchase of preferred shares.

The total working interest in lands held at the end of the year was up by 9% to 266,000 net hectares. The increase was due mainly to growth in land holdings in Alberta.

In the multi-zone Spirit River area of northern Alberta, ATCOR participated in 5 wells, the first 3 of which were drilled deep, and the remainder of which were shallow wells aimed at following up the Doe Creek oil discovery made in the initial tests of this program. While the full potential of this new oil pool has not been established, results to date have been highly encouraging, and at least 6 more wells are scheduled in 1986 to further evaluate ATCOR's extensive land holdings in the area.

The Doe Creek has been aggressively developed further south at Valhalla and Saddle Hills in recent years, and has responded well to enhanced oil recovery techniques. Enhanced recovery techniques are being researched by ATCOR for the Doe Creek at Spirit River, and a carefully designed enhanced recovery project should commence later in 1986.

An encouraging new pool discovery was drilled at Chauvin in east-central Alberta in 1985, and was rapidly followed by a successful confirmation well. Both wells were completed in the Lloydminster sand and each well is producing 4 to 8 cubic metres of oil per day. Considerable potential was also found in the Sparky and General Petroleum sands on the same structure. A development program is currently underway and will continue into 1986.

ATCOR's exploration effort is being expanded, and new work will reflect strategies aimed at increasing working interests in reserves, particularly gas.

Gas Processing

ATCOR processed an average of 6.0 million cubic metres per day of

Crude oil and natural gas reserves

	Gross Before Royalties		
	Proven	Probable	Total
Crude oil and gas liquids (10^3m^3)			
1985 (after carve-out)	455	402	857
(before carve-out)	726	611	1 337
1984	751	826	1 577
Natural gas (10^6m^3)			
1985 (after carve-out)	1 090	336	1 426
(before carve-out)	1 281	376	1 657
1984	1 101	434	1 535

Petroleum and natural gas rights

	Hectares	
	Gross	Net
Alberta	259,490	86,670
Saskatchewan	14,490	6,874
British Columbia	4,021	800
Manitoba	4,711	1,499
	282,712	95,843
Petroleum rights only (Alberta)	340,037	169,668
Total 1985	622,749	265,511
Total 1984	602,363	243,325

natural gas in 1985 at its 50%-owned south Edmonton ethane extraction plant. The plant, which has the capacity to process 8.9 million cubic metres of gas per day, produced 225,000 cubic metres of ethane and 86,000 cubic metres of LPG's for ATCOR's account during the year. In addition, approximately $2.1 million in revenues were generated from gas processed on a fee basis.

A major expansion to the Edmonton plant in the form of additional compression was completed during the year. The compression increase will permit the processing of extra volumes of gas resulting from 2 large custom processing contracts. Initial deliveries on one of these contracts commenced in 1985. The processing contracts are expected to last for a minimum of 10 years.

Plans for the construction of 2 natural gas liquids recovery plants in the Carbon and Joffre areas of Alberta have been revised. The ethane extraction facility proposal for Joffre has been placed on hold, pending an improvement in ethane markets. Negotiations for the right to extract liquids from the gas stream at Joffre are underway. A final decision to construct a plant at Carbon will be made once some stability has been restored to product pricing and the economics of the revised project are found to be acceptable.

Gas Marketing

ATCOR markets natural gas to large industrial customers for use as fuel and feedstock as well as to resource companies for enhanced oil recovery projects. In addition to marketing its own gas, ATCOR purchases gas from various producers for resale. During 1985, ATCOR sold 87 petajoules of natural gas, an increase of 14% from 1984; the total number of contracts increased to 23. Gas was supplied by 52 producing companies under approximately 90 separate contracts.

The Agreement on Natural Gas Markets and Prices announced in October 1985 is likely to have a minimal impact on ATCOR until after November 1, 1986, when natural gas prices are fully deregulated. Upon full deregulation, it is anticipated that the cost of gas to the consumer will be reduced somewhat as a result of increased competition among brokers to generate direct sales from producers to industrial customers. This will lead to a corresponding reduction in the well-head price to producers and lower brokerage margins for spot gas sales in the market.

ATCOR is sufficiently well established in the industry to withstand the effects of this competition. ATCOR will endeavour to replace a portion of brokerage revenue lost due to lower margins with increased sales to new customers. In the longer term, deregulation is expected to create new opportunities in eastern Canadian industrial markets and in export markets. ATCOR is involved in pursuing new opportunities in these areas.

AT&S

AT&S, a joint exploration company in which ATCOR holds a 30% interest, was involved in the drilling of 16 exploration wells during the year of which 2 were oil discoveries, 2 were gas discoveries, 3 resulted in both oil and gas discoveries, and 9 were dry holes for a success ratio of 44%. The company currently holds or has the right to earn interests in 3.9 million hectares (approximately 118,000

hectares net) in the Canada Lands.

AT&S participated in the drilling of 2 wells on a western extension of the Venture gas field, offshore Nova Scotia. One of the wells, N-91, blew out after encountering high pressure gas sands. While the external blowout was immediately contained, an underground blowout occurred and remedial action to control the well took many months and involved the drilling of 2 relief wells. Testing of the same high pressure sands in the second well was abandoned due to the very high risk.

AT&S has had the most success in the Beaufort Sea-Mackenzie Delta area where the company is an associate in the Esso-Home program and in several Gulf operated programs. Of greatest significance to the future of AT&S is the successful follow-up to the Amauligak J-44 discovery of 1984. The follow-up Amauligak I-65 well, drilled in late 1985, was an outstanding success.

Subject to confirmation by further delineation, the prospect appears to have sufficient hydrocarbons to be the first commercial development in the Beaufort Sea. Recoverable reserves were estimated by Gulf Canada Resources to be between 600 and 700 million barrels of oil, and in excess of one trillion cubic feet of gas. Five tests were carried out on the I-65 well on separate sand zones and all tested at rates between 4,800 and 7,200 barrels per day. AT&S negotiated the right to increase its interest in the Amauligak program from 3.0% to a maximum of 12.6% by participating in the drilling of 3 delineation wells, to be directionally drilled from the I-65 location. The first delineation well has been completed, giving AT&S an earned interest of 6.2% and drilling is currently underway on the second delineation well.

FINANCIAL REVIEW

Earnings attributable to Class A and Class B shares reached a record high of $111.9 million ($2.07 per share) in 1985 compared to $101.4 million ($1.87 per share) for the previous year.

Consolidated revenues were $1.326 billion in 1985 compared to $1.364 billion in 1984. Natural gas revenues declined slightly to $854.2 million from $861.2 million due to the removal of certain Federal excise taxes which were collected in natural gas rates, and to lower natural gas sales to industrial customers. The effect of these decreases more than offset rate increases and weather-related increases in sales to residential and commercial customers.

Electric power revenues fell to $323.9 million from $340.3 million last year, reflecting rate decisions issued by the Alberta Public Utilities Board for 1984 and 1985, which were both accounted for in the current year. A surge in retail electricity sales during the year significantly reduced the effects of the rate decrease.

Non-utility energy sales volumes continued on an upward trend. However, falling oil and gas prices, the sale of certain working interests in oil and gas reserves, together with increased inter-company sales to the natural gas utilities, caused a decline in non-utility revenues from $162.2 million in 1984 to $147.2 million in 1985.

Earnings per Class A and Class B Share

	1985	1984	Change
	$	$	$
Electric	**1.12**	1.16	(.04)
Natural Gas	**.97**	.63	.34
Non-Utility — Energy	**(.10)**	.14	(.24)
— Other	**.08**	(.06)	.14
	2.07	1.87	.20

The timing of regulatory decisions and the effects of weather can have a major impact on utility earnings. Earnings were improved by higher natural gas utility rates in 1985 and the combined effect of a cold December 1984, the revenues for which were received in 1985, and a warm December 1985 which reduced gas supply expense in that month.

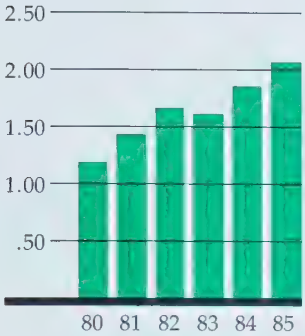
The electric utility was required by the Alberta Public Utilities Board to refund part of 1984 revenues and to reduce 1985 revenues. The effect on earnings, however, was moderated by the increase in retail sales and continued efforts to achieve cost savings.

Continued uncertainties in world oil markets necessitated a review of the Company's non-utility oil and gas reserves. As a result, the value of oil and gas assets of ATCOR Resources was written down to a level consistent with the net realizable value. Consequently, a net loss was reported from non-utility energy operations.

The net carrying cost of the TransAlta Utilities investment was capitalized during 1985. In addition, approximately 1.2 million warrants to purchase TransAlta shares from the Company were exercised, producing an after-tax gain of $2.7 million.

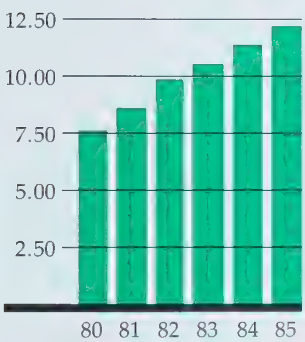
At the conclusion of 1985, there were 27,832,900 Class A non-voting and 26,378,674 Class B common shares outstanding for a total of 54,211,574, un-

Earnings per Class A and Class B Share
(dollars)



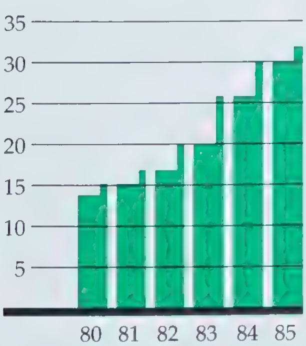
Annual Growth Rate 11.7%

Equity per Class A and Class B Share
(dollars)



Annual Growth Rate 9.9%

Dividends per Class A and Class B Share
(quarterly rate in cents)



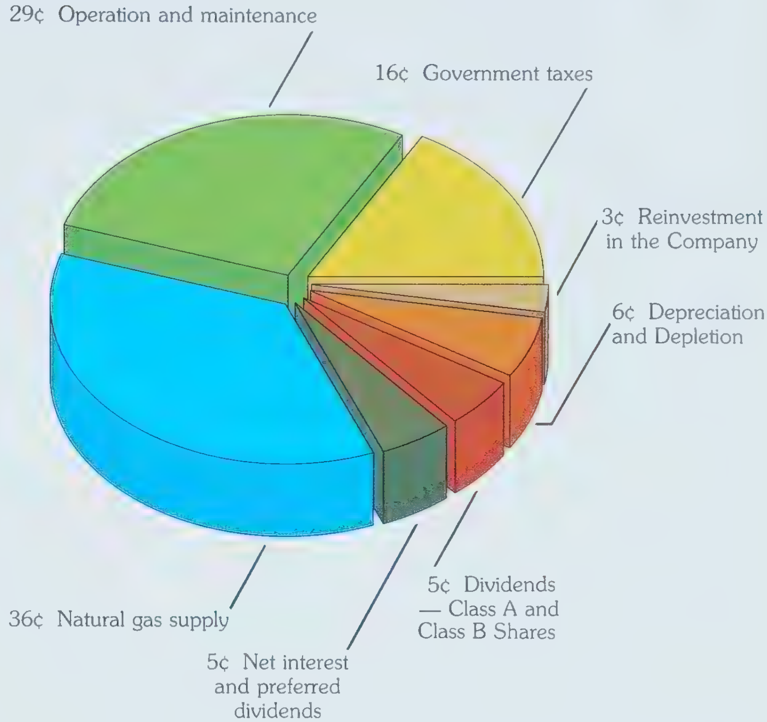
Annual Growth Rate 16.3%

changed from December 31, 1984. The Class A shares were distributed among 9,047 shareholders of whom 8,992 were Canadian residents. The Class B shares were held by 2,150 holders of whom 2,117 were Canadian residents. The total shares held by non-residents represented less than 1% of the total shares outstanding. During the year, 248,455 Class B shares were exchanged for an equal number of Class A shares. A more detailed explanation of the rights and privileges accorded these 2 classes of shares is contained in the notes to the consolidated financial statements. The Company's shares are listed on the Toronto, Montreal and Alberta stock exchanges.

In 1985, the Company's quarterly dividend rate was 30¢ per share in each of the first 3 quarters and was increased to 32¢ in the fourth quarter. The annual dividend of $1.22 in 1985 represented 59% of the $2.07 earnings per share in 1985.

Capital additions in 1985 were $235.6 million. The Company's net investment in property, plant and equipment rose $120.6 million to $2.083 billion. Construction of the Sheerness Generating Station Unit 1 was completed during the year and it was commissioned on January 1, 1986. Approval has been obtained from The Alberta Energy Resources Conservation Board to delay the commissioning of Unit 2 until 1990. The delay was requested following Alberta Electric Utility Planning Council forecasts of reduced growth in electric energy demand in the Province. Additions to electric utility property, plant and

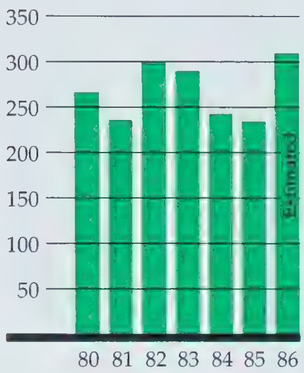
WHERE THE REVENUE DOLLAR WAS SPENT



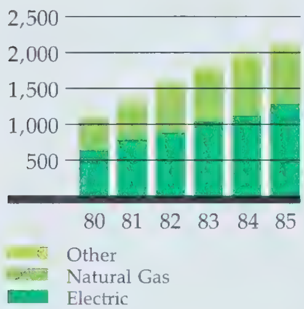
Capital Expenditures

	1985	1986 Estimate
	($ Millions)	
Electric	**142.0**	188.7
Natural Gas	**69.0**	90.6
Non-Utility		
Energy	**24.4**	28.0
Other	**.2**	1.5
	235.6	308.8

Capital Expenditures
(millions of dollars)

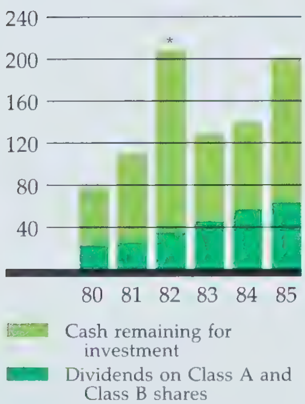


Property, Plant and Equipment — net By Type of Business
(millions of dollars)



Annual Growth Rate Total 14.0%
Electric 14.3%
Gas 12.7%
Other 23.2%

Cash Provided from Operations
(millions of dollars)



* Results include a short term deferral of income tax payments on the change to the normalized — all taxes paid method of accounting for income taxes.

equipment totalled $142.0 million, of which $78.9 million was spent on the Sheerness project.

Capital additions in natural gas utility operations totalled $69.0 million. The largest item was the completion of the Lethbridge-Taber transmission line replacement. In addition, 2 more salt caverns were commissioned bringing 4 of the 5 planned caverns into operation.

ATCOR Resources Limited's capital additions totalled $24.4 million, the largest segment being the investment in exploration and production.

The projected capital expenditure program for the next 5 years in CU is currently forecast at $1.6 billion. This forecast is subject to change, depending upon economic activity in Alberta, and could be affected by the current instability in world oil prices.

Long-term external financings in 1985 totalled $138.2 million. The major financing was the October 1985 issue of $125 million Series K Preferred Shares at a rate of 7.80%. The proceeds were applied primarily to the redemptions of the 10.24% Series D Preferred Shares and the 9.24% Series B Preferred Shares. The balance was used to finance the Company's ongoing capital expenditure program.

Other financings included an $8.7 million finance contract for the purchase of the second Sheerness Generating Station turbine and an increase of $4.5 million in the note payable to the Rural Electrification Associations.

The Company's capital structure includes the $288.6 million Series H Preferred Share issue which was used to finance the investment in TransAlta Utilities Corporation. This issue represents the expected proceeds from disposition of the Company's investment in TransAlta. The Company regards its investment in TransAlta as self-liquidating in nature and expects total divestiture of its investment to occur on or before November 1, 1987. Each Series H Preferred Share carried a detachable warrant, entitling the bearer to purchase one Class A common share of TransAlta, owned by CU, at a price of $22.25 per share, on or before November 1, 1987.

The Company has been successful in retaining its high credit standing on senior debt and preferred equity instruments. CU's credit rating position on senior debt instruments is AAA and A+ (High) and its preferred shares are rated Pfd-1 and P1 by the 2 major Canadian rating agencies.

FINANCIAL STATEMENTS

The corporate computer facilities located in Edmonton were further upgraded during 1985 to keep pace with growing information processing requirements.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The consolidated financial statements and other financial information relating to the Company contained in this annual report have been prepared by management, which is responsible for the integrity and objectivity of this information. The financial information contained elsewhere in this annual report is consistent with that in the consolidated financial statements. The consolidated financial statements have been prepared in conformity with generally accepted accounting principles as applied to regulated utilities and conform in all material respects with International Accounting Standards. Where management makes a choice from acceptable alternatives it uses methods which it believes are prudent. These consolidated financial statements necessarily include some amounts that are based on informed judgements and best estimates of management.

Management depends upon a system of internal accounting controls to meet its responsibility for reliable and accurate reporting which includes periodic review by the internal audit function. Management modifies and improves its system of internal accounting controls in response to changes in business conditions.

Price Waterhouse, the Company's independent auditors, are engaged to express a professional opinion on the consolidated financial statements. The examination is conducted in accordance with generally accepted auditing standards and includes tests and other procedures which allow the auditors to report on the fairness of the consolidated financial statements prepared by management.

Under provisions of the Canada Business Corporations Act, the Board of Directors appoints certain of its members to serve on the Audit Committee. The Board of Directors, through this committee comprised of 5 non-management directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and financial matters, gain assurance that management is carrying out its responsibilities and to review and approve the financial statements. The auditors have full and free access to the Audit Committee.

AUDITORS' REPORT

To the Shareholders of Canadian Utilities Limited:

We have examined the consolidated balance sheet of Canadian Utilities Limited as at December 31, 1985 and the consolidated statements of earnings and retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the Company as at December 31, 1985 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Price Waterhouse

Chartered Accountants

Edmonton, Canada
January 31, 1986

CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS

	Note	1985	1984
		Year ended December 31	
		(Thousands)	
Revenues		**$1,325,936**	$1,364,430
Operating Expenses			
Natural gas supply	1	**479,273**	517,280
Operation and maintenance		**376,971**	375,418
Taxes — other than income	2	**98,405**	118,646
Taxes — income	3	**108,791**	108,544
Depreciation and depletion	4	**82,650**	65,187
		1,146,090	1,185,075
		179,846	179,355
Allowance for Funds Used During Construction		**46,926**	39,459
Other Income	5	**8,860**	31,268
		235,632	250,082
Interest Expense		**75,849**	75,469
Dividends on Preferred Shares	13	**47,834**	73,208
		123,683	148,677
Earnings Attributable to Class A and Class B Shares		**111,949**	101,405
Retained Earnings at Beginning of Year		**285,474**	242,618
		397,423	344,023
Dividends on Class A and Class B Shares	14	**66,138**	58,549
Retained Earnings at End of Year		**$ 331,285**	$ 285,474
Earnings per Class A and Class B Share		**$ 2.07**	$ 1.87

CONSOLIDATED BALANCE SHEET

	Note	December 31 1985	December 31 1984
		(Thousands)	
ASSETS			
Current Assets			
Cash and short-term investments		$ 21,977	$ 27,033
Accounts receivable	6	135,582	169,606
Materials and supplies		26,303	18,632
Natural gas stored		5,355	2,661
Prepaid expenses		2,890	4,141
		192,107	222,073
Investment in TransAlta Utilities Corporation	7	226,981	244,148
Property, Plant and Equipment	8	2,082,844	1,962,206
Deferred Expenses	9	49,925	40,853
		$2,551,857	$2,469,280
LIABILITIES AND CAPITALIZATION			
Current Liabilities			
Due to bank		$ 22,504	$ 24,798
Accounts payable and accrued liabilities		192,520	186,494
Income and other taxes		20,333	32,266
Dividends payable		12,221	12,525
Long-term debt — current maturities		19,269	11,225
		266,847	267,308
Deferred Credits			
Contributions for extensions to plant		190,071	169,331
Deferred income taxes		18,354	16,993
Other	10	40,961	45,543
		249,386	231,867
Capitalization			
Long-term debt	12	581,783	603,193
Preferred shares	13	791,930	750,812
Class A and Class B shareholders' equity	14	661,911	616,100
		2,035,624	1,970,105
		$2,551,857	$2,469,280

APPROVED BY THE BOARD:

J. D. Wood, Director

D. R. B. McArthur, Director

CONSOLIDATED STATEMENT OF CHANGES IN FINANCIAL POSITION

	1985	1984
	(Thousands)	
CASH PROVIDED FROM OPERATIONS		
Earnings attributable to Class A and Class B shares	**$111,949**	$101,405
Depreciation and depletion	**82,650**	65,187
Other	**4,584**	12,806
Allowance for funds used during construction — shareholders' equity	**(19,230)**	(15,748)
Decrease (increase) in working capital	**18,699**	(26,862)
	198,652	136,788
Dividends on Class A and Class B Shares	**66,138**	58,549
Cash Remaining for Investment	**132,514**	78,239
INVESTMENT		
Additions to property, plant and equipment	**235,618**	242,478
Increase (decrease) in deferred expenses for natural gas exploration — net	**3,969**	(1,041)
Allowance for funds used during construction — shareholders' equity	**(19,230)**	(15,748)
	220,357	225,689
Investment in TransAlta Utilities Corporation		
— Net carrying cost	**5,130**	
— Proceeds on disposition of shares	**(25,928)**	(480)
Disposition of property, plant and equipment	**(22,294)**	(1,628)
Increase in other deferred expenses	**6,184**	1,103
	183,449	224,684
Cash Deficiency before Financing	**50,935**	146,445
FINANCING		
Issue of long-term debt	**13,154**	100,000
Reduction in long-term debt	**(26,520)**	(20,956)
Contributions for extensions to plant	**26,879**	18,905
Issue of preferred shares	**125,000**	27,000
Preferred shares redeemed	**(82,972)**	(26,425)
Preferred shares purchased for cancellation	**(910)**	(2,670)
Other	**(6,458)**	216
	48,173	96,070
Decrease in Cash	**$ 2,762**	$ 50,375

"Long-term debt — current maturities" and cash are excluded from working capital. Cash is defined as "Cash and short-term investments" less "Due to bank."

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES December 31, 1985

Consolidated Financial Statements

The consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles and conform in all material respects with the International Accounting Standards adopted by the International Accounting Standards Committee.

The consolidated financial statements include the accounts of the Company, the utility subsidiaries, Alberta Power Limited (electric), Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited (natural gas), and a non-utility subsidiary, ATCOR Resources Limited.

Regulation

The utility subsidiaries are regulated primarily by the Public Utilities Board of Alberta (the Board) and the Energy Resources Conservation Board of Alberta, which administer acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The Board may award interim rates, subject to final determination. Decisions made by these authorities or management which impact on operating results or utility accounting policies are reflected in the consolidated financial statements after the date of decision.

Revenue Recognition

Customers are billed on a cycle billing basis and revenues are recognized when billed with the exception that final Board decisions relating to:

(a) prior years revenues are recorded in the current year at the date of decision
(b) current year revenues collectible or refundable in a subsequent year are recorded at the end of the current year.

Natural Gas Supply

The Province of Alberta enacted the Natural Gas Rebates Act effective January 1, 1974 to shelter the majority of Alberta natural gas customers from the full impact of significant price increases for natural gas. Under the provisions of the Act, the natural gas subsidiaries incur a lower effective cost for natural gas in that they are reimbursed for the portion of the price paid to their suppliers which exceeds the support price.

Taxes — Income

Income taxes are provided by the utility subsidiaries, using the normalized—all taxes paid method approved by the Board. This method does not result in a deferral of income taxes as any timing differences between accounting earnings and taxable income are eliminated. The major portion of income taxes paid is refunded for rebate to customers under the Public Utilities Income Tax Transfer Act and the Utility Companies Income Tax Rebates Act.

Prior to adoption of this method, the utility subsidiaries provided for income taxes on the flow-through method which resulted in a deferral of income taxes. As the income tax component of rates is designed to recover only income taxes currently payable, no provision has been made in the consolidated financial statements for this deferral of income taxes. The customer in future years will bear an additional charge in the event of a reversal of these unbooked deferred income taxes. Significant reversals are not expected in the foreseeable future.

The Company and its non-utility subsidiary provide for deferred income taxes except where under the terms of a cost of service agreement, the subsidiary is only allowed to recover income taxes currently payable in the revenues billed.

Inventories

Inventories are valued at the lower of cost or net realizable value. Costs for materials and supplies are determined on an average basis, whereas the cost of natural gas stored is determined on a first-in, first-out basis.

Deferred Expenses

The natural gas subsidiaries include in gas exploration all costs, including an allowance for funds, related to the development of gas reserves. These costs are recorded net of income taxes. Costs related to a successful venture are capitalized as plant and equipment. The costs of an unsuccessful venture are charged against amounts received under The Natural Gas Pricing Agreement Act included in other deferred credits.

Expenses of issue of long-term debt are amortized over the weighted average life of the debt, and expenses of issue of preferred shares are amortized over the expected life of the issue. Premiums and unamortized issue costs of redeemed long-

term debt and preferred shares are amortized over the life of the issue funding the redemption.

Property, Plant and Equipment

The utility subsidiaries include in the cost of additions an allowance for funds used during construction, at a rate approved by the Board for debt and equity funds.

Certain additions are made with the assistance of cash contributions where the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

On retirement of depreciable assets, the accumulated depreciation is charged with the cost of the retired unit less net salvage. Gains and losses on extraordinary retirements are recognized in earnings as extraordinary items.

Included in the natural gas subsidiaries' Property, Plant and Equipment are gas wells that have been drilled, tested and capped and remain unconnected to the utility system. The Board has directed that the costs of such wells, including an allowance for funds, be accounted for as plant held for future use. If, after a period of five years, these wells have not been added to the utility system, the costs are written off against funds received under The Natural Gas Pricing Agreement Act. If at a future date a gas well is placed in service or is required to be used, the amount written off will be reinstated in Property, Plant and Equipment.

The non-utility subsidiary follows the full cost method of accounting for petroleum and natural gas properties whereby all costs relating to the exploration for, and development of, petroleum and natural gas reserves are capitalized. The capitalized cost of petroleum and natural gas properties is limited to an amount equivalent to the present value of future net revenues from estimated production of proved reserves plus the lower of cost or estimated fair value of non-producing properties.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. The major assets are depreciated using rates approved by the Board varying from 1.5% to 6.4%. All resource properties are depleted on a unit of production basis.

Leases

The Board requires that application be made for the capitalization of leases in the determination of customer rates. Prior to such approval, leases that would otherwise be treated as capital leases are accounted for as operating leases.

Deferred Credits — Other

As Alberta gas producers, the natural gas subsidiaries receive a pro rata share of monies available under The Natural Gas Pricing Agreement Act. The amounts received, net of royalties and income taxes, are deferred and, subject to Board approval, are reduced by the costs of unsuccessful natural gas exploration.

Preferred Shares

The preferred dividends are recorded in the same manner as interest expense in the consolidated statement of earnings and retained earnings.

The capitalization segment of the consolidated balance sheet and the consolidated statement of earnings and retained earnings reflect the financing and cost of capital policies of the Company as a regulated utility in Alberta.

Alberta Electric Energy Marketing Agency

The Province of Alberta has established the Alberta Electric Energy Marketing Agency to reduce rate differentials for Alberta consumers by the purchase and resale of energy. The Agency buys energy from the utilities at each utility's cost of generation and transmission and resells identical quantities of energy at an average cost. The electric subsidiary receives funds monthly from the Agency and deposits these funds in a special trust account for rebate to its customers.

1. Natural gas supply

The natural gas supply expense is net of a rebate from the Province of Alberta of $109,397,000 (1984 — $102,755,000).

2. Taxes — other than income

	Year ended December 31	
	1985	1984
	(Thousands)	
Federal Canadian ownership taxes	**$22,064**	$ 30,004
Federal natural gas and gas liquids taxes		15,662
Federal petroleum and natural gas revenue taxes	**5,984**	7,067
	28,048	52,733
Franchise taxes	**56,937**	52,290
Property taxes	**12,524**	12,388
Provincial mineral taxes	**896**	1,235
	$98,405	$118,646

No natural gas and gas liquids taxes and Canadian ownership taxes have been levied since February 1, 1984 and June 1, 1985 respectively.

3. Taxes — income

Under the normalized – all taxes paid method of accounting for income taxes the expected rate of income tax on accounting earnings would equal the statutory rate in the absence of permanent differences. The following table describes the permanent differences and their effect on the statutory rate:

	Year ended December 31	
	1985	1984
Statutory income tax rate	**47.9%**	47.0%
Allowance for funds used during construction	**(5.2)**	(4.1)
Crown royalties and other non-deductible Crown payments	**3.6**	3.4
Earned depletion and resource allowance	**(3.6)**	(4.3)
Dividend income		(3.2)
Reassessments	**(2.3)**	
Other	**.1**	(.5)
Actual income tax rate	**40.5%**	38.3%

Taxes — income includes deferred income taxes of $1,222,000 (1984 — $4,246,000) provided for timing differences in the Company and its non-utility subsidiary.

As a result of income tax reassessments, Taxes — income has been reduced by $6,107,000. Had the changes been applied retroactively, the income tax expense of each of the years would have been increased (decreased) as follows:

1981	$(6,199,000)
1982	(1,544,000)
1983	1,103,000
1984	533,000
	$(6,107,000)

A provision for certain deferred income taxes is not included in the consolidated financial statements. Unbooked deferred income taxes increased during the year by $5,344,000 (1984 — decrease of $1,960,000) to an accumulated amount of $134,515,000.

4. Depreciation and depletion

The carrying value of the non-utility subsidiary's petroleum and natural gas properties was written down by $17,725,000 ($12,895,000 after income taxes) to a value based on a report prepared by independent petroleum engineers and management estimates.

5. Other income

	Year ended December 31	
	1985	1984
	(Thousands)	
Interest	**$2,972**	$ 9,521
Dividends	**629**	19,394
Gain on purchase of long-term debt	**1,085**	1,862
Gain on disposition of shares	**3,631**	119
Other	**543**	372
	$8,860	$31,268

6. Accounts receivable

	December 31	
	1985	1984
	(Thousands)	
Customer accounts by segment — natural gas	**$ 66,892**	$ 82,832
— electric	**20,616**	16,355
— energy	**19,757**	21,814
Receivable from the Province of Alberta	**12,947**	29,622
Other receivables and deposits	**15,370**	18,983
	$135,582	$169,606

7. Investment in TransAlta Utilities Corporation

On August 3, 1982, the Company, ATCO Ltd. and TransAlta Utilities Corporation entered into an agreement providing for the divestiture of the interlocking equity ownership positions held by the Company and TransAlta Utilities Corporation.

On December 1, 1982, each Series H preferred shareholder was issued a warrant, for each share held, entitling the bearer to purchase one Class A common share of TransAlta Utilities Corporation owned by the Company at a price of $22.25 per share on or before November 1, 1987. The investment in TransAlta Utilities Corporation was acquired at a price of $18.81 per share. During the year, 1,152,316 (1984 — 200) warrants were exercised, leaving 11,817,201 outstanding.

Effective January 1, 1985, the net carrying cost of the investment has been deferred and added to the cost of the investment. The market value of the TransAlta Utilities Corporation shares had increased such that, in management's opinion, it was appropriate to defer this cost until gains are realized on the exercise of the warrants.

Included in the deferred amount of $5,130,000 are dividends on the Series H preferred shares of $25,779,000 and other costs of $2,230,000; net of dividends received on the TransAlta Utilities Corporation shares of $20,519,000 and related interest income of $2,360,000.

8. Property, plant and equipment

	December 31			
	1985		1984	
	Cost	**Accumulated Depreciation**	Cost	Accumulated Depreciation
	(Thousands)		(Thousands)	
Natural gas plant and equipment	**$ 978,016**	**$221,354**	$ 913,670	$198,389
Electric plant and equipment	**1,092,623**	**264,661**	1,041,844	232,847
Construction work in progress	**400,496**		321,592	
Non-regulated petroleum and natural gas properties	**102,127**	**43,790**	99,817	18,914
Other plant and equipment	**35,921**	**10,909**	30,635	9,192
Land	**14,375**		13,990	
	$2,623,558	**$540,714**	$2,421,548	$459,342
Net property, plant and equipment	**$2,082,844**		$1,962,206	

The Company's electric subsidiary has a 50% joint ownership in the construction and operation of Sheerness Generating Stations 1 and 2. These are included in construction work in progress in the amount of $373,336,000 (1984 — $295,841,000). On the commissioning of Unit 1 on January 1, 1986, $273,429,000 was transferred from construction work in progress to electric plant and equipment. Unit 2 is expected to be commissioned in 1990.

Plant held for future use in the amount of $24,213,000 (1984 — $30,399,000) is included in natural gas plant and equipment.

9. Deferred expenses

	December 31	
	1985	1984
	(Thousands)	
Gas exploration — net	**$24,508**	$20,539
Unamortized debt and preferred share issue expenses	**19,082**	18,465
Other	**6,335**	1,849
	$49,925	$40,853

10. Deferred credits — other

	December 31	
	1985	1984
	(Thousands)	
Funds received under The Natural Gas Pricing Agreement Act — net	**$34,224**	$35,076
Other	**6,737**	10,467
	$40,961	$45,543

During the year, $1,944,000 (1984 —$nil) of unsuccessful gas exploration costs, net of related income taxes, were charged against monies received under The Natural Gas Pricing Agreement Act.

11. Bank line of credit

Under a bank loan agreement, which provides a line of credit of up to $50,000,000 to March 14, 1987, the Company issues commercial paper and assumes bank loans. Under the agreement the Company maintains an unused bank line of credit of not less than 50% of the commercial paper outstanding. At December 31, 1985 and 1984, there were no loans outstanding under this agreement.

12. Long-term debt

Long-term debt outstanding, net of current maturities, is as follows:

	December 31	
	1985	1984
	(Thousands)	
Canadian Utilities Limited		
Sinking fund debentures 8⅜% to 17.50% due to 2002	**$480,572**	$504,504
Capitalized lease obligation due 1996	**19,362**	20,256
Finance contracts at 9.118% due to 1993	**13,775**	6,930
Note payable due 1987	**12,500**	8,000
Alberta Power Limited		
First mortgage sinking fund bonds 5½% to 6½% due to 1992	**20,000**	25,000
Sinking fund debentures 7¼% to 9⅝% due to 1991	**13,776**	14,844
Northwestern Utilities Limited		
First mortgage sinking fund bonds 5¾% to 9¾% due to 1994	**10,823**	12,009
Canadian Western Natural Gas Company Limited		
First mortgage sinking fund bonds 5⅝% to 7% due to 1992	**6,225**	6,525
Sinking fund debentures 9¾% due 1990	**4,750**	5,125
	$581,783	$603,193

The $12,500,000 note payable is owing to Rural Electrification Associations and bears interest determined at June 30 and December 31 of each year at the greater of a bank's prime rate or its five-year term deposit rate.

Annual repayment of maturing issues, capitalized lease and finance contract requirements and sinking fund requirements for each of the following years are:

	Maturing Issues	Capitalized Lease and Finance Contracts	Sinking Fund Requirements	Sinking Fund Purchased in Advance	Total
		(Thousands)			
1986	$ 5,000	$2,174	$24,417	$(12,322)	$19,269
1987	47,500	2,243	24,417	(4,117)	70,043
1988	11,940	3,376	23,352	(396)	38,272
1989	2,125	3,918	23,227	(8)	29,262
1990	15,625	4,005	22,852		42,482

The $100,000,000 13.10% debentures 1984 series, due June 1, 1994, grants the holder of the debentures the option of requiring the Company to redeem all or any of the holder's debentures on June 1, 1989 at a price equal to the principal amount plus accrued and unpaid interest to June 1, 1989.

The Company leases, with an option to purchase, a dragline costing $24,818,000 which is included in electric plant and equipment. The future minimum lease payments in aggregate are $31,961,000 of which $2,421,000 is payable in each of the five succeeding years. Included in these future minimum rentals is $11,704,000 of imputed interest at the rate of 7.62%.

13. Preferred shares

	December 31		Dividends Year ended December 31	
	1985	1984	**1985**	1984
	(Thousands)		**(Thousands)**	
Canadian Utilities Limited	**$751,922**	$710,804	**$71,382**	$70,923
Northwestern Utilities Limited	**10,500**	10,500	**420**	420
Canadian Western Natural Gas Company Limited	**9,508**	9,508	**440**	440
ATCOR Resources Limited	**20,000**	20,000	**1,371**	1,425
	40,008	40,008	**2,231**	2,285
	791,930	750,812	**73,613**	73,208
Less dividends capitalized (Note 7)			**25,779**	
	$791,930	$750,812	**$47,834**	$73,208

(Note 13 continued)

Canadian Utilities Limited

Authorized:

40,000 5% Cumulative Redeemable Preferred Shares.

150,000 Series Preferred Shares, issuable in series, which have been designated as Cumulative Redeemable Preferred Shares and rank pari passu with the 5% Cumulative Redeemable Preferred Shares.

An unlimited number of Series Second Preferred Shares, issuable in series, which have been designated as Cumulative Redeemable Second Preferred Shares.

Issued:

	December 31			
	1985		1984	
	Shares	**Amount**	Shares	Amount
		(Thousands)		(Thousands)
Cumulative Redeemable Preferred Shares				
5%	**40,000**	**$ 4,000**	40,000	$ 4,000
Cumulative Redeemable Preferred Shares				
4¼% Series	**15,000**	**1,500**	15,000	1,500
6% Series	**50,000**	**5,000**	50,000	5,000
Cumulative Redeemable Second Preferred Shares				
Non-retractable				
9.24% Series B			1,391,600	34,790
7.30% Series C	**957,580**	**23,940**	993,580	24,840
		34,440		70,130
Retractable				
10.24% Series D			1,927,700	48,192
10.12% Series E	**2,124,100**	**53,103**	2,124,100	53,103
14.00% Series F	**2,998,100**	**74,952**	2,998,100	74,952
14.50% Series G	**2,000,000**	**50,000**	2,000,000	50,000
9.00% Series H	**12,971,900**	**288,625**	12,971,900	288,625
8.74% Series I	**3,952,100**	**98,802**	3,952,100	98,802
8.375% Series J	**1,080,000**	**27,000**	1,080,000	27,000
7.80% Series K	**5,000,000**	**125,000**		
		717,482		640,674
		$751,922		$710,804

During 1985, the Company redeemed the 10.24% and 9.24% Cumulative Redeemable Second Preferred Shares Series D and Series B. The redemption price was $26 per share and $25.25 per share, plus $0.3165 and $0.3734 of accrued dividends, respectively. The Company issued for cash $125,000,000 of Cumulative Redeemable Second Preferred Shares Series K.

(Note 13 continued)

Stated values, redemption premiums and dividends:

	Stated Value	1986 Redemption Premium	Dividends Year ended December 31 1985	1984
			(Thousands)	
Cumulative Redeemable Preferred Shares				
5%	$100	4%	$ 200	$ 200
Cumulative Redeemable Preferred Shares				
4¼% Series	$100	2½%	64	64
6% Series	$100	2%	300	300
Cumulative Redeemable Second Preferred Shares				
Non-retractable				
10¼% Series A	$ 25			471
9.24% Series B	$ 25		3,123	3,253
7.30% Series C	$ 25	1.6%	1,769	1,843
			5,456	6,131
Retractable				
10.24% Series D	$ 25		3,892	4,935
10.12% Series E	$ 25	4%	5,374	5,374
14.00% Series F	$ 25	4%	10,493	10,494
14.50% Series G	$ 25		7,250	7,250
9.00% Series H	$ 22.25		25,976	25,976
8.74% Series I	$ 25		8,618	8,694
8.375% Series J	$ 25		2,266	2,069
7.80% Series K	$ 25		2,057	
			65,926	64,792
			$71,382	$70,923

Redemption privileges

The preferred shares of the Company are redeemable subject to premiums listed above plus accrued dividends. The Cumulative Redeemable Preferred Shares and the non-retractable Cumulative Redeemable Second Preferred Shares are redeemable at the option of the Company at any time. The retractable Cumulative Redeemable Second Preferred Shares will be subject to redemption at the option of the Company commencing at the dates specified and with an initial premium as stated:

		Redemption Premium
Series E	March 1, 1986	4%
Series F	October 1, 1986	4%
Series G	May 1, 1987	4%
Series H	November 1, 1987	Nil
Series I	November 1, 1988	4%
Series J	January 31, 1992	Nil
Series K	October 15, 1993	Nil

On January 30, 1986, the Company approved the redemption of the Series E shares effective March 3, 1986.

(Note 13 continued)

Purchase obligations

The Company is required in each year to make all reasonable efforts to purchase for cancellation the number of shares of the Cumulative Redeemable Second Preferred Shares listed below at a price not exceeding $25 per share plus costs of purchase. If after all reasonable efforts the Company is unable to do so, the Company's obligation to purchase in such year is extinguished.

	1985 Share Purchase Obligations	Purchased in 1985 Shares	Amount
			(Thousands)
			$
Series B	48,000		
Series C	36,000	36,000	900
Series D	48,910	400	10
Series E	44,000		
Series F	119,924		
Series G	80,000		
Series I	120,000		
			$910

Retraction privileges

Certain series of the Cumulative Redeemable Second Preferred Shares have retraction privileges on specified dates at the option of the holder at the stated value plus accrued dividends. The series and retraction dates are shown below:

Series E	March 1, 1988
Series F	October 1, 1989
Series G	May 1, 1987
Series H	November 1, 1987
Series I	November 1, 1991
Series J	January 31, 1992
Series K	October 15, 1993

The Series H Cumulative Redeemable Second Preferred Shares can be redeemed at the option of the holder prior to November 1, 1987 if presented with a warrant to purchase a Class A common share of TransAlta Utilities Corporation.

(Note 13 continued)

Northwestern Utilities Limited

	December 31	
	1985	1984
	(Thousands)	
Authorized and issued:		
105,000, 4% Cumulative Redeemable Preferred Shares — $100; voting, non-participating, 1986 redemption premium — 4%	**$10,500**	$10,500

Canadian Western Natural Gas Company Limited

	December 31	
	1985	1984
	(Thousands)	
Authorized and issued:		
275,410, 4% Cumulative Redeemable Preferred Shares — $20; voting, non-participating, 1986 redemption premium — 3%	**$5,508**	$5,508
200,000, 5½% Cumulative Redeemable Preferred Shares — $20; voting, non-participating, 1986 redemption premium — 3%	**4,000**	4,000
	$9,508	$9,508

ATCOR Resources Limited

	December 31	
	1985	1984
	(Thousands)	
Authorized and issued:		
800,000 Floating Rate Cumulative Redeemable Preferred Shares — $25; guaranteed by the Company, dividend rate of one-half of bank prime rate plus 1¼%, redemption of $2,000,000 per year commencing in 1989 — nil premium	**$20,000**	$20,000

14. Class A and Class B shareholders' equity

	December 31		Dividends Year ended December 31	
	1985	1984	**1985**	1984
	(Thousands)		**(Thousands)**	
Class A non-voting shares	**$169,742**	$168,227	**$33,670**	$29,693
Class B common shares	**160,884**	162,399	**32,468**	28,856
Retained earnings	**331,285**	285,474		
	$661,911	$616,100	**$66,138**	$58,549

Class A and Class B shares

Authorized:

An unlimited number of Class A non-voting shares and Class B common shares without nominal or par value.

Issued:

	Year ended December 31, 1985			
	Class A non-voting		Class B common	
	Shares	Amount	Shares	Amount
		(Thousands)		(Thousands)
Beginning of year	27,584,445	$168,227	26,627,129	$162,399
Share exchanges	248,455	1,515	(248,455)	(1,515)
End of year	27,832,900	$169,742	26,378,674	$160,884

The holders of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by the Company on either of such classes of shares as well as the remaining property of the Company upon dissolution. The holders of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share. The holders of the Class A non-voting shares are entitled to exchange, in limited circumstances, each share held for one Class B common share.

During the year, options to purchase 555,000 Class A non-voting shares were granted to 10 officers of the Company and its subsidiaries. The Class A non-voting shares subject to the option may be purchased at the price of $16.75 per share on or before February 25, 1995. The effect of potential exercise of these options would not materially dilute earnings per Class A and Class B shares.

Retained earnings

The bond and debenture indentures place certain limitations on the Company which include restrictions on the payment of dividends on Class A and Class B shares. Consolidated retained earnings in the amount of $186,617,000 was free from such restrictions.

15. Amounts held in trust

	December 31	
	1985	1984
	(Thousands)	
Rural Electrification Associations	$15,918	$14,427
Income tax rebates	14,298	5,312
Alberta Electric Energy Marketing Agency	1	1,161
	$30,217	$20,900

Amounts held in trust are not included in the consolidated financial statements.

16. Related party transactions

During 1985, the Company entered into transactions with ATCO Ltd., its principal shareholder, and certain subsidiaries of ATCO Ltd. These transactions are considered to be in the normal course of business and at fair market value.

Payments were made to ATCO Ltd. for the rental of premises of $11,676,000 (1984 — $11,522,000) and equipment purchases of $913,000 (1984 — $726,000). A subsidiary of ATCO Ltd. acted as a general contractor for construction of a warehouse facility and office leasehold improvements for which fees, including administration costs, amounted to $130,000 (1984 — $176,000). The Company was reimbursed by ATCO Ltd. and certain of its subsidiaries for the provision of security services in the amount of $532,000 (1984 — $279,000). Charges to ATCO Ltd. for rental of premises and recovery of costs of leasehold improvements were $163,000 (1984 — $105,000).

Certain subsidiaries of the Company participate in oil and natural gas joint ventures. When they act as operator they have, in some instances, contracted ATCO Ltd. subsidiaries for well drilling and servicing, equipment purchases and related services, the total amount being approximately $5,600,000 (1984 — $3,700,000). A portion of these expenditures is reimbursed by the other participants in the joint ventures.

Effective April 1, 1985, the non-utility subsidiary of the Company sold for $17,000,000 certain working interests in oil and gas reserves to an affiliated company, ATCO Drilling Ltd. The ownership of these reserves reverts to the subsidiary in the event that ATCO Drilling Ltd. receives from production sufficient income to return its investment plus a pre-determined rate of return on that investment.

17. Rate applications

One of the natural gas subsidiaries received a final rate decision for 1985 on December 20, 1985 and revenues of $3,656,000 have been accrued at December 31, 1985. The other natural gas subsidiary has been operating on interim rates since October 1984 and final decisions for 1984 and 1985 are expected in early 1986.

In a final decision released in December 1985, the Board set the revenue requirements of the electric subsidiary for 1984 and 1985. The decision, requiring a revenue refund of approximately $13,255,000 for 1984 ($5,693,000 after income taxes and other related expenses) and $29,087,000 for 1985, has been recorded in the current year.

18. Employee pension plan

The Company and its subsidiaries have a defined benefit pension plan covering substantially all employees. Employees participate through contributions to the plan which provides for pensions based on length of service and final average earnings. During the year, the Company made no changes to the benefits offered by the plan which uses the accrued benefit cost method with projection of employee compensation levels to determine the costs of the reporting period. Pension costs for the year amounted to $12,579,000 (1984 — $12,181,000) including amortization of past service costs and experience deficiencies of $4,345,000 (1984 — $4,656,000). Based on the most recent actuarial evaluation, December 31, 1983, the estimated plan deficit now amounts to $28,879,000. Of this deficit $1,843,000 is a result of plan experience and is being amortized and funded over 3 years. The balance of $27,036,000 arising from changes in plan assumptions is being amortized and funded over periods ranging from 3 to 13 years.

19. Commitments and contingencies

The electric subsidiary has a 50% joint ownership in the Sheerness Generating Station which is under construction. The project presently is forecast to cost the subsidiary approximately $587,000,000 of which $214,000,000 is yet to be expended.

Minimum non-capitalized lease payments, which extend over periods not exceeding 18 years, are $12,203,000, $11,849,000, $11,471,000, $11,263,000 and $11,056,000 for the years 1986-1990, respectively.

The utility subsidiaries purchase natural gas and coal from approximately 346 producers under approximately 576 purchase contracts. Substantially all of these contracts have provisions requiring payment when the company is unable to nominate specified minimum annual quantities for delivery. In prior years, the available market has exceeded the minimum contract supply quantities and no "take-or-pay" payments were required.

During 1984 and 1985, a major customer took less than the minimum annual volume of natural gas it had contracted to take from a natural gas subsidiary. The subsidiary filed a Statement of Claim in 1984 for $1,545,000 to recover the amount due under the sales contract. An agreement has since been reached whereby the customer agrees to indemnify the subsidiary from any past or future take-or-pay exposure with regard to 20 of the 22 producers supplying natural gas dedicated to the major customer. Litigation has been suspended pending negotiations on the remaining items of disagreement. Of the 2 remaining producers, agreement has also been reached with the producer supplying the largest volume of natural gas and its Statement of Claim for $575,000 has been withdrawn and there is no outstanding take-or-pay obligation with the other.

20. Segmented information

Operating segments	Year	Electric Utility Operations	Natural Gas Utility Operations	Non-Utility Energy Operations	Consolidated*
		(Thousands)			
Revenues					
Outside customers	**1985**	**$ 323,903**	**$854,164**	**$147,237**	**$1,325,304**
	1984	$ 340,345	$861,218	$162,203	$1,363,766
Inter-segment		**166**	**28,205**	**20,642**	
		144	23,147	7,073	
Corporate					**632**
					664
		324,069	**882,369**	**167,879**	**1,325,936**
		340,489	884,365	169,276	1,364,430
Expenses					
Operating		**150,002**	**709,181**	**144,043**	**954,214**
		141,419	755,413	144,206	1,010,674
Taxes — income		**46,165**	**57,383**	**2,949**	**106,497**
		60,356	36,373	9,643	106,372
Depreciation and depletion		**30,475**	**25,559**	**26,572**	**82,442**
		34,072	22,945	8,147	64,972
Corporate					**2,937**
					3,057
		226,642	**792,123**	**173,564**	**1,146,090**
		235,847	814,731	161,996	1,185,075
Segment operating income	**1985**	**$ 97,427**	**$ 90,246**	**$ (5,685)**	**$ 179,846**
	1984	$ 104,642	$ 69,634	$ 7,280	$ 179,355
Total assets	**1985**	**$1,292,837**	**$907,461**	**$125,994**	**$2,551,857**
	1984	$1,172,917	$894,179	$136,104	$2,469,280
Capital expenditures	**1985**	**$ 141,975**	**$ 69,022**	**$ 24,385**	**$ 235,618**
	1984	$ 147,709	$ 72,925	$ 28,922	$ 242,478

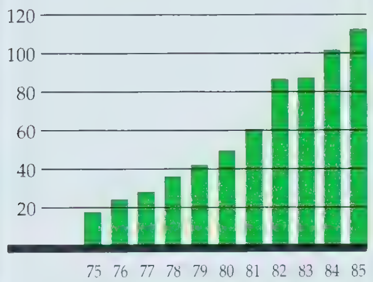
* Inter-segment transactions have been eliminated in the consolidated column. Consolidated total assets and capital expenditures include the other assets and expenditures of the Company. The principal other asset included in the consolidated total is the investment in TransAlta Utilities Corporation.

21. Financial statements

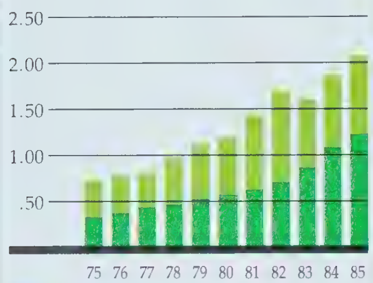
Certain of the 1984 figures have been reclassified to conform with the consolidated financial statement presentation adopted in 1985.

CONSOLIDATED TEN-YEAR FINANCIAL SUMMARY

Earnings Attributable to Class A and Class B Shares
(before extraordinary items)
(millions of dollars)

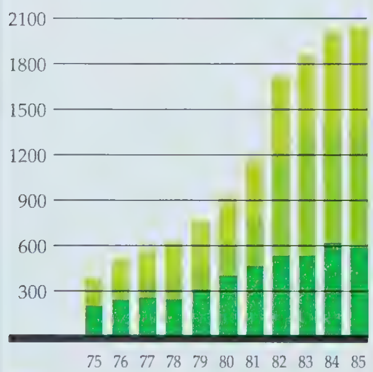


Earnings per Class A and Class B Share
(before extraordinary items)
(dollars)



Earnings retained per share
Dividends per share

Capitalization
(millions of dollars)



Shareholders' equity
Preferred shares (including minority interests)
Long-term debt

(Dollars in millions, except as indicated)

	1985
Operating Revenues	
Natural Gas	854.2
Electric	323.9
Non-Utility	
Energy	147.2
Other	.6
	1,325.9
Operating Expenses	
Natural gas supply	479.3
Operation and maintenance	377.0
Taxes — other than income	98.4
Taxes — income	108.8
Depreciation and depletion	82.6
	1,146.1
	179.8
Allowance for Funds Used During Construction	46.9
Other Income	8.9
	235.6
Interest Expense	75.9
Dividends on Preferred Shares	47.8
Earnings before Extraordinary Items	111.9
Extraordinary Items — Non-Recurring Gain (Loss)	
Earnings attributable to Class A and Class B Shares	111.9
Contribution by Segment	
Electric	60.8
Natural gas	52.4
Non-Utility	
Energy	(5.6)
Other	4.3
	111.9
Shares Outstanding* (thousands)	
At end of year	54,212
Average for year	54,212
Earnings per Share*# (dollars)	2.07
Total Annual Dividends*	66.1
Dividends per Share* (dollars)	1.22
Payout Ratio (dividends ÷ earnings attributable)	59.1%
Equity per Share* (dollars)	12.21
Return on Equity*#	17.5%
Stock Market Record — Class A non-voting shares High	19⅝
Low	16½
Close	19¼
Stock Market Record — Class B common shares High	19⅝
Low	16½
Close	19⅜
Property, Plant and Equipment — Gross	2,623.6
— Net	2,082.8
Total Assets	2,551.9
Capitalization	
Long-term debt	581.8
Preferred shares	791.9
Total long-term debt and preferred shares	1,373.7
Shareholders' equity*	661.9
Total capitalization	2,035.6
Capitalization Ratio	
Long-term debt	29%
Preferred shares	39%
Shareholders' equity*	32%
Times Debt Interest Earned (pretax)	4.54

* Includes Class A non-voting shares and Class B common shares.
Where Class A and Class B shares are presented, the comparative figures have been reclassified to reflect the September 10, 1982 two-for-one share reorganization.

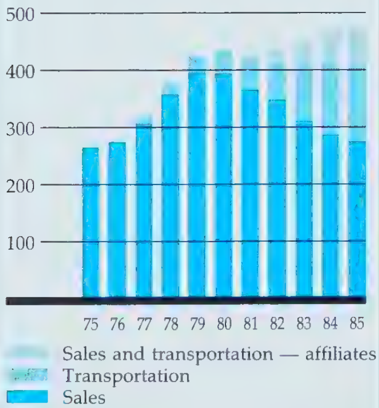
\# All information expressed before extraordinary items.

1984	1983	1982	1981	1980	1979	1978	1977	1976	1975
861.2	928.4	959.1	779.2	581.7	477.9	431.8	318.7	216.5	141.8
340.3	327.2	316.3	201.7	149.8	124.6	114.7	93.9	78.1	57.9
162.2	123.6	116.3	42.9	25.4	22.9	7.5	2.5	1.0	.5
.7	.6	.8	.8	.8	.3	.2	.3	.3	.2
1,364.4	1,379.8	1,392.5	1,024.6	757.7	625.7	554.2	415.4	295.9	200.4
517.3	512.6	444.8	442.2	405.8	342.3	315.5	221.3	134.8	70.9
375.4	327.3	326.2	212.5	166.3	139.1	107.2	87.2	72.8	56.5
118.7	231.3	329.4	195.8	53.2	28.0	26.6	21.8	17.0	11.8
108.5	92.7	78.5	30.6	21.6	17.5	20.0	12.5	8.6	8.7
65.2	56.8	53.1	36.8	29.5	26.5	23.2	18.8	15.6	13.3
1,185.1	1,220.7	1,232.0	917.9	676.4	553.4	492.5	361.6	248.8	161.2
179.3	159.1	160.5	106.7	81.3	72.3	61.7	53.8	47.1	39.2
39.5	33.2	15.8	24.6	19.7	7.1	4.7	2.3	1.3	4.0
31.3	30.8	27.2	6.8	2.7	1.5	2.5	1.4	2.3	1.4
250.1	223.1	203.5	138.1	103.7	80.9	68.9	57.5	50.7	44.6
75.5	69.1	74.1	53.7	39.5	27.4	22.4	21.4	22.3	19.9
73.2	66.9	43.1	23.8	14.9	11.7	10.9	8.4	4.7	6.0
101.4	87.1	86.3	60.6	49.3	41.8	35.6	27.7	23.7	18.7
							(1.6)		2.4
101.4	87.1	86.3	60.6	49.3	41.8	35.6	26.1	23.7	21.1
62.9	61.3	45.6	34.9	29.3	21.7	18.7	15.4	12.8	10.7
34.2	26.2	33.0	21.5	17.6	18.1	15.7	11.7	10.8	7.9
7.8	5.6	5.1	2.3	1.7	1.9	1.1	.2	.1	.1
(3.5)	(6.0)	2.6	1.9	.7	.1	.1	.4		
101.4	87.1	86.3	60.6	49.3	41.8	35.6	27.7	23.7	18.7
54,212	54,212	53,806	45,936	41,636	41,636	37,252	34,244	33,268	28,396
54,212	53,807	50,910	41,822	41,984	37,566	36,293	34,624	31,134	28,516
1.87	1.62	1.69	1.44	1.19	1.12	.99	.81	.78	.73
58.5	46.3	35.8	26.1	23.8	18.9	16.4	14.4	11.0	7.1
1.08	.86	.71	.63	.57	.51	.46	.43	.38	.33
57.7%	53.2%	41.5%	43.1%	48.3%	45.2%	45.9%	55.2%	46.4%	33.6%
11.36	10.57	9.82	8.59	7.61	7.00	6.11	5.53	5.18	4.71
17.1%	15.9%	18.4%	17.8%	16.3%	17.1%	17.0%	15.1%	15.8%	16.3%
17	16¼	16							
13¼	11¾	8½							
17	15¾	15¾							
17	16⅛	15½	12½	13½	10½	9	7¾	7¼	5
13¼	12	9¼	9¾	9⅛	8	7⅛	6⅜	4¾	3⅞
17	15¾	15½	10⅞	11⅜	9½	8⅛	7¾	7¼	4⅞
2,421.5	2,179.4	1,890.9	1,594.6	1,324.1	1,059.3	883.9	780.5	688.6	613.6
1,962.2	1,787.9	1,559.9	1,318.5	1,083.7	849.4	700.1	618.8	542.3	478.6
2,469.3	2,366.8	2,222.6	1,602.7	1,314.1	1,000.6	832.9	731.5	632.0	564.1
603.2	527.2	527.0	453.3	393.6	302.2	233.7	244.3	225.7	181.1
750.8	752.9	654.6	321.2	196.2	148.3	149.2	129.3	99.3	55.3
1,354.0	1,280.1	1,181.6	774.5	589.8	450.5	382.9	373.6	325.0	236.4
616.1	573.2	528.6	394.6	316.2	290.3	226.9	187.5	173.9	138.6
1,970.1	1,853.3	1,710.2	1,169.1	906.0	740.8	609.8	561.1	498.9	375.0
31%	28%	31%	39%	43%	41%	38%	44%	45%	48%
38%	41%	38%	27%	22%	20%	25%	23%	20%	15%
31%	31%	31%	34%	35%	39%	37%	33%	35%	37%
4.75	4.57	3.81	3.14	3.17	3.59	3.97	3.27	2.66	2.68

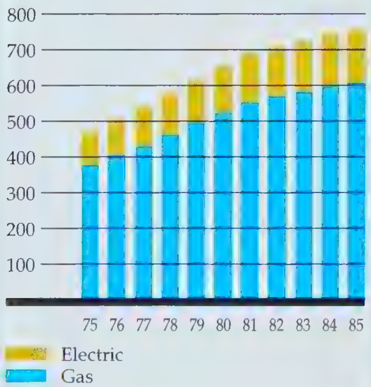
CONSOLIDATED TEN-YEAR OPERATING SUMMARY

Electric Sales
(millions of kilowatt hours)

Natural Gas System Throughput
(petajoules)



Gas and Electric Customers at Year-end
(thousands)



(Dollars in millions, except as indicated)

	1985
Electric Operations	
Property, plant and equipment in service	1,097.8
Construction work in progress	396.8
Property, plant and equipment — gross	1,494.6
Accumulated depreciation	264.7
Property, plant and equipment — net	1,229.9
Growth over prior year	9%
Capital expenditures	142.0
Sales (millions of kilowatt hours) — retail	4,331
— other utilities	1,290
Growth retail sales over prior year	12%
Average annual use per residential customer (kWh)	7,432
Average annual billing per residential customer ($)	660
Maximum hourly demand (thousands of kilowatts)	844
Generating capacity (thousands of kilowatts)	1,058
Customers at year-end (thousands)	147.1
Number of communities served	348
Power lines (thousands of kilometres)	39.1
Natural Gas Operations	
Property, plant and equipment — gross	990.7
Accumulated depreciation	221.3
Property, plant and equipment — net	769.4
Growth over prior year	5%
Capital expenditures	69.0
Sales (petajoules)	274
Transportation (petajoules)	131
Sales and transportation — affiliates (petajoules)	70
Total system throughput (petajoules)	475
Growth over prior year	1%
Average annual use per residential customer (gigajoules)	176
Average annual billing per residential customer ($)	621
Maximum daily demand (terajoules)	2,304
Degree days — Edmonton	5,414
— Calgary	5,124
Customers at year-end (thousands)	601.8
Number of communities served	292
Pipelines (thousands of kilometres)	32.8
Non-Utility Energy Operations	
Property, plant and equipment — gross	133.9
Accumulated depreciation	53.9
Property, plant and equipment — net	80.0
Production	
Oil (m^3/d)	206
Gas ($10^3m^3/d$)	228
Ethane (m^3/d)	616
LPGs (m^3/d)	235
Reserves	
Oil (10^3m^3)	857
Gas (10^6m^3)	1,426
Total Number of Employees	4,144

984	1983	1982	1981	1980	1979	1978	1977	1976	1975
046.8	987.9	911.2	817.8	493.2	439.8	407.2	358.6	332.7	295.0
314.5	227.3	130.3	68.9	243.8	107.7	31.5	34.4	20.0	14.3
361.3	1,215.2	1,041.5	886.7	737.0	547.5	438.7	393.0	352.7	309.3
232.8	195.5	158.8	127.3	106.7	89.9	75.4	62.2	53.2	45.7
128.5	1,019.7	882.7	759.4	630.3	457.6	363.3	330.8	299.5	263.6
11%	16%	16%	21%	38%	26%	10%	10%	14%	20%
147.7	171.8	157.2	153.5	190.1	110.7	48.1	44.1	45.9	51.1
3,882	3,618	3,452	3,216	2,994	2,779	2,512	2,358	2,182	2,025
1,265	1,552	1,196	495	34	113	192	228		
7%	5%	7%	7%	8%	11%	7%	8%	8%	5%
7,264	7,044	7,436	6,988	7,073	7,162	7,058	6,764	6,773	6,673
660	643	661	474	405	366	358	310	281	223
741	720	693	652	607	573	520	524	455	445
1,055	1,056	1,058	1,054	670	668	668	671	686	686
143.4	139.9	136.6	134.6	128.8	120.1	112.5	106.9	99.6	94.0
334	340	332	329	328	325	316	314	301	307
37.5	34.6	29.2	25.3	23.7	23.0	22.3	20.8	20.1	19.3
929.6	863.2	757.9	624.7	553.9	479.8	416.8	370.9	333.9	300.8
198.4	175.9	159.9	142.9	129.7	117.7	107.6	99.3	93.0	89.3
731.2	687.3	598.0	481.8	424.2	362.1	309.2	271.6	240.9	211.5
6%	15%	24%	14%	17%	17%	14%	13%	14%	10%
72.9	108.8	135.5	80.9	75.6	64.5	48.2	38.8	39.4	29.5
286	308	347	364	392	392	357	304	273	264
124	98	63	51	42	30	16	12		
61	45	26	11	2	1	2			
471	451	436	426	436	423	375	316	273	264
4%	3%	2%	(2%)	3%	13%	18%	16%	3%	5%
166	162	196	165	190	207	201	190	195	224
580	586	625	434	336	308	299	241	190	156
2,119	2,147	2,063	2,048	2,051	2,003	1,978	1,681	1,508	1,390
5,349	5,362	6,025	4,595	5,396	5,636	5,530	5,124	4,891	5,555
5,021	4,953	5,602	4,365	5,082	5,366	5,592	5,289	4,885	5,750
593.6	580.7	566.6	549.8	520.0	489.8	457.4	428.4	400.5	373.3
293	289	285	272	269	272	265	260	257	253
32.1	31.1	30.4	29.3	27.9	27.1	25.0	23.1	21.8	19.5
125.9	97.0	87.6	79.2	29.3	28.2	26.3	15.5		
26.9	19.0	11.4	5.1	3.3	1.9	.3			
99.0	78.0	76.2	74.1	26.0	26.3	26.0	15.5		
260	189	158	142	79	67				
125	170	170	121	125	119				
651	736	780	952	1,039	1,044				
200	170	184	190	189	192				
1,577	1,408	889	750	766	694				
1,535	1,224	1,182	1,186	1,144	944				
4,099	4,168	4,212	4,313	4,144	3,870	3,592	3,367	3,161	3,133

Board of Directors

W. L. Britton, Q.C.°
Barrister and Solicitor
Bennett Jones
Calgary, Alberta

G. L. Crawford, Q.C.°+
Barrister and Solicitor
McLaws & Company
Calgary, Alberta

B. K. French*
President
Karusel Management Ltd.
Calgary, Alberta

V. L. Horte°
President
V. L. Horte Associates Limited
Calgary, Alberta

W. R. Horton°
Executive Vice-President, Utilities
Canadian Utilities Limited
Edmonton, Alberta

H. E. Joudrie+
President and
Chief Executive Officer
Dome Canada Limited
Calgary, Alberta

E. W. King*
Corporate Director
Edmonton, Alberta

R. W. A. Laidlaw+
President and Chief Executive Officer
Gibson Petroleum Company Limited
Calgary, Alberta

C. M. Leitch, Q.C.*
Barrister and Solicitor
MACLEOD DIXON
Calgary, Alberta

D. R. B. McArthur*
Corporate Director
Edmonton, Alberta

W. S. McGregor
President and Chief Executive Officer
Numac Oil & Gas Ltd.
Edmonton, Alberta

C. S. Richardson°
Deputy Chairman of the Board
and Chief Financial Officer
Canadian Utilities Limited
Calgary, Alberta

D. M. Ritchie°
President
Medway Investments Corporation Ltd.
Edmonton, Alberta

N. W. Robertson*
President and
Chief Operating Officer
ATCO Ltd.
Calgary, Alberta

R. D. Southern°
Chairman of the Board and
Chief Executive Officer
Canadian Utilities Limited
Calgary, Alberta

J. D. Wood°+
President and
Chief Operating Officer
Canadian Utilities Limited
Edmonton, Alberta

° member of the Executive Committee
* member of the Audit Committee
+ member of The Human Resources Committee

Officers and Staff Executives

R. D. Southern
Chairman of the Board and
Chief Executive Officer

C. S. Richardson
Deputy Chairman
of the Board and
Chief Financial Officer

J. D. Wood
President and
Chief Operating Officer

W. R. Horton
Executive Vice-President, Utilities

H. N. Bottomley
Vice-President,
Finance and Administration

D. B. Mitchell
Vice-President,
Human Resources and
Corporate Services

A. E. Scott
Vice-President,
Corporate Planning
and Economics

A. M. Anderson
Secretary

C. K. Sheard
General Counsel and
Assistant Secretary

J. H. Cook
Assistant Secretary

D. P. Wood
Assistant Secretary

J. A. Walker
Treasurer

DIRECTORS & OFFICERS

Subsidiary Company Executives

ALBERTA POWER LIMITED

R. D. Southern
Chairman of the Board and
Chief Executive Officer

J. D. Wood
Deputy Chairman
of the Board

W. R. Horton
President and
Chief Operating Officer

C. O. Twa
Senior Vice-President and
General Manager

R. H. Choate
Vice-President, Administration

J. R. Frey
Vice-President, Planning

D. B. Mitchell
Vice-President,
Human Resources

J. E. A. Morin
Vice-President,
Engineering and Construction

G. N. Paicu
Vice-President, Energy Supply

H. R. Lewis
Vice-President and Controller

P. K. F. McEwen
Vice-President,
Customer Services

A. M. Anderson
Secretary/Treasurer

J. H. Cook
Assistant Secretary

C. K. Sheard
Assistant Secretary

D. P. Wood
Assistant Secretary

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

and

NORTHWESTERN UTILITIES LIMITED

R. D. Southern
Chairman of the Board and
Chief Executive Officer

J. D. Wood
Deputy Chairman of the Board

W. R. Horton
President and
Chief Operating Officer

B. M. Dafoe
Senior Vice-President

A. J. L. Fisher
Vice-President and
General Manager
Canadian Western Natural
Gas Company Limited

R. G. Lock
Vice-President and
General Manager
Northwestern Utilities
Limited

W. L. Graburn
Vice-President, Gas Supply

D. B. Mitchell
Vice-President,
Human Resources

A. M. Anderson
Secretary/Treasurer

R. M. Massé
Controller, Northwestern
Utilities Limited

T. J. Storey
Controller, Canadian
Western Natural Gas
Company Limited

J. H. Cook
Assistant Secretary

C. K. Sheard
Assistant Secretary

D. P. Wood
Assistant Secretary

ATCOR RESOURCES LIMITED

R. D. Southern
Chairman of the Board

J. D. Wood
Deputy Chairman
of the Board

W. A. Elser
President and
Chief Executive Officer

D. L. Weiss
Vice-President,
Gas Processing and Marketing

R. A. Johnson
Vice-President, Exploration
and Production

D. H. Boyle
Treasurer

R. E. Pratt
Controller

D. P. Wood
Secretary

A. M. Anderson
Assistant Secretary

CANADIAN UTILITIES LIMITED

Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

Registered Head Office

10035 - 105th Street
Edmonton, Alberta, Canada
T5J 2V6
Telephone: (403) 420-7310

Valuation Day

The Valuation Day price of Canadian Utilities' Class A non-voting and Class B common shares adjusted for the stock split of September 15, 1972 and the replacement of common shares by the Class A and B shares on September 10, 1982 was $4.66.

Annual Meeting

The annual meeting of shareholders will be held April 24, 1986 at the Four Seasons Hotel, Edmonton, Alberta.

Auditors

Price Waterhouse
2401 Toronto Dominion Tower
Edmonton Centre
Edmonton, Alberta T5J 2Z1

Transfer Agents and Registrars

Halifax/Montreal/Toronto/Winnipeg/Regina/Calgary/Edmonton/Vancouver

Class A non-voting and Class B common shares, Preferred, Series Preferred and Second Preferred (Series C, F, G, I, K and L) Shares
The Royal Trust Company

Second Preferred Shares, Series H
The Canada Trust Company

Trustee and Registrar

Montreal/Toronto/Winnipeg/Calgary/Edmonton/Vancouver

Debentures
National Trust Company

Stock Exchange Listings

Class A non-voting and Class B common shares
Toronto, Montreal and Alberta Stock Exchanges

Preferred and Series Preferred Shares
Toronto Stock Exchange

Second Preferred (Series C, F, G, H, I, K and L) Shares
Toronto and Montreal Stock Exchanges

Euro-Dollar Debentures
London Stock Exchange

CANADIAN UTILITIES LIMITED
AN ATCO COMPANY

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CANADIAN UTILITIES LIMITED

Notice of Annual and Special Meeting of Shareholders
April 24, 1985

NOTICE IS GIVEN that the Fifty-Eighth Annual and Special Meeting of Shareholders of Canadian Utilities Limited will be held at the Four Seasons Hotel, Edmonton, Alberta on Wednesday, the 24th day of April, 1985 at the hour of 10:00 o'clock in the forenoon, Mountain Standard Time, for the following purposes:

1. to receive and consider the annual report containing the consolidated financial statements for the year ended December 31, 1984, accompanied by the report of the auditor;
2. to consider and, if deemed appropriate, to pass a special resolution (the full text of which is set out in the Management Proxy Circular) amending the articles of the Corporation to increase the minimum number of directors from 3 to 5;
3. to consider and, if deemed appropriate, to pass a resolution to confirm the establishment of the Stock Option Plan for designated employees of the Corporation or its subsidiaries;
4. to elect directors;
5. to appoint the auditor;
6. to consider and, if deemed appropriate, to pass a resolution to confirm certain amendments made by the directors to By-law No. 1 of the Corporation (the text of the resolution of the directors making such amendments accompanies the Management Proxy Circular as Exhibit "A"); and
7. to transact such other business as may properly be brought before the Annual and Special Meeting or an adjournment thereof.

DATED at Edmonton, Alberta this 15th day of March, 1985.

By Order of the Board,

A.M. Anderson

A.M. Anderson
Secretary

If you are unable to attend the meeting kindly complete and sign the accompanying form of proxy and return it in the envelope provided to reach the Corporation at least 24 hours, excluding Saturdays and holidays, preceding the Annual and Special Meeting or an adjournment thereof.

MANAGEMENT PROXY CIRCULAR

SOLICITATION OF PROXIES

This Management Proxy Circular is furnished in connection with the solicitation by the management of CANADIAN UTILITIES LIMITED (the "Corporation") of proxies to be used at the Annual and Special Meeting of Shareholders of the Corporation to be held at the time and place and for the purposes set forth in the accompanying notice. It is expected that the solicitation will be primarily by mail. Proxies may also be solicited personally by officers and employees of the Corporation. The cost of the solicitation by the management will be borne by the Corporation.

APPOINTMENT OF PROXYHOLDER AND REVOCATION OF PROXY

The persons named in the accompanying form of proxy are directors of the Corporation. A shareholder entitled to vote at the Annual and Special Meeting may by means of a proxy appoint a proxyholder and one or more alternate proxyholders, who are not required to be shareholders, other than the persons designated in the accompanying form of proxy, to attend and act at the Annual and Special Meeting in the manner and to the extent authorized by the proxy and with the authority conferred by the proxy. This right may be exercised either by striking out the names of the persons designated in the form of proxy and inserting in the space provided the name of the other person or persons a shareholder wishes to appoint or by completing and executing another proper form of proxy. A shareholder desiring to be represented at the Annual and Special Meeting by a proxyholder must deposit a proxy with the Corporation at least 24 hours, excluding Saturdays and holidays, preceding the Annual and Special Meeting or an adjournment thereof.

A shareholder may revoke a proxy by depositing an instrument in writing executed by the shareholder or by the shareholder's attorney authorized in writing at the registered office of the Corporation, 1927, 10035 - 105 Street, Edmonton, Alberta, T5J 2V6, at any time up to and including the last business day preceding the day of the Annual and Special Meeting, or an adjournment thereof, at which the proxy is to be used, or with the chairman of the Annual and Special Meeting on the day of the Annual and Special Meeting or an adjournment thereof.

CLASS B COMMON SHARES AND PRINCIPAL HOLDERS THEREOF

There are outstanding 26,624,290 Class B common shares of the Corporation entitled to be voted at the Annual and Special Meeting. Each Class B common share entitles the holder thereof to one vote. The directors have fixed March 15, 1985 as the record date for determining shareholders entitled to receive notice of the Annual and Special Meeting of Shareholders.

To the knowledge of the directors and officers of the Corporation, the only persons who beneficially own or exercise control or direction over shares of the Corporation carrying more than 10% of the votes attached to the shares of the Corporation are ATCO Ltd. ("ATCO") and TransAlta Resources Corporation ("TransAlta Resources"), a wholly-owned subsidiary of TransAlta Utilities Corporation ("TransAlta Utilities"). ATCO indirectly owns 13,578,552 Class B common shares, being approximately 51.0% of the Class B common shares outstanding. R. D. Southern controls ATCO. Reference is made to "Election of Directors". TransAlta Resources owns 7,818,544 Class B common shares, being approximately 29.4% of the Class B common shares outstanding. On August 3, 1982 the Corporation, ATCO and TransAlta Utilities entered into an agreement (the "Divestiture Agreement") intended to resolve certain differences among the corporations arising from reciprocal shareholdings. In addition to other matters, the Divestiture Agreement provides that the Corporation and TransAlta Utilities shall (a) vote in favour of any corporate reorganization; and (b) not oppose any other matter proposed by the other at shareholders' meetings except as to a vote upon a corporate reorganization or upon any other matter which would materially reduce the value to the Corporation or TransAlta Utilities of its investment in the shares of the other corporation. On November 25, 1983 TransAlta Resources issued warrants to purchase 7,856,250 Class B common shares of the Corporation at the price of $15.00 per share on or before December 15, 1987. In the event that all of the warrants are exercised, TransAlta Utilities will have divested itself of all of its presently held Class B common shares of the Corporation.

CLASS A NON-VOTING SHARES

The holders of the Class A non-voting shares of the Corporation are entitled to receive notice of the Annual and Special Meeting of Shareholders and to attend and participate in discussions at the Annual and Special Meeting, but are not entitled to vote at the Annual and Special Meeting.

The holders of the Class A non-voting shares are also entitled, in certain circumstances briefly described below, and subject to changes in the exchange ratio also described below, to exchange their Class A non-voting shares for Class B common shares on the basis of one Class A non-voting share for each Class B common share.

The rights of exchange attaching to the Class A non-voting shares in certain circumstances are set out in a Certificate of Amendment dated September 10, 1982 issued to the Corporation. Events giving rise to the rights of exchange include: (a) certain take-over bids where the offeror will in result own, together with the offeror's previously owned Class B common shares, more than 50% of the outstanding Class B common shares, and (b) ATCO, the present controlling shareholder of the Corporation, ceasing to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of the Corporation. The rights afforded to the holders of Class A non-voting shares in the nature of take-over bid protection are limited. A holder of Class A non-voting shares shall only be entitled to the take-over bid protection rights described in the Certificate of Amendment or as may otherwise be conferred by law. Should a take-over bid be made in circumstances other than those therein described, a holder of Class A non-voting shares shall have no right to tender such shares in exchange for Class B common shares of the Corporation.

VOTING OF PROXIES

All Class B common shares of the Corporation represented by a proxy in favour of the persons designated in the accompanying form of proxy will be voted or withheld from voting on any ballot that may be called for in accordance with the instructions of the shareholder contained in the proxy. Where no choice is specified by the shareholder in the proxy, the proxy will be voted in favour of the five specific matters referred to therein.

The accompanying form of proxy confers discretionary authority in respect of amendments to matters identified in the Notice of Annual and Special Meeting of Shareholders and in respect of other matters that may properly come before the Annual and Special Meeting. The management of the Corporation is not aware of any amendments to matters identified in the Notice of Annual and Special Meeting of Shareholders or of other matters that are to be presented for action at the Annual and Special Meeting.

AMENDMENT TO THE ARTICLES OF THE CORPORATION REGARDING DIRECTORS

Under the articles of the Corporation the board of directors may consist of a minimum of 3 and a maximum of 18 directors. It is proposed that the articles of the Corporation be amended to increase the minimum number from 3 to 5. The text of the proposed special resolution to increase the minimum number of directors is as follows:

BE IT RESOLVED as a special resolution that:

(1) item 5 of the Articles of Continuance of the Corporation be amended so that the minimum number of directors of the Corporation is 5 and the maximum number is 18; and

(2) any one of the officers or directors of the Corporation be authorized to take all actions and to execute and deliver all documents as may be necessary or desirable for the implementation of this special resolution including, without limitation, executing and delivering articles of amendment in prescribed form.

The special resolution is required to be passed by the affirmative vote of not less than 66.67% of the votes cast at the Annual and Special Meeting of Shareholders.

STOCK OPTION PLAN

The directors of the Corporation have approved a stock option plan as an employee incentive, to be called the Stock Option Plan. Under this proposed plan, the Chairman of the Board of the Corporation may designate employees of the Corporation or its subsidiaries to be offered options to purchase in aggregate 700,000 Class A non-voting shares of the Corporation. The price to be paid upon the exercise of any option granted will be the closing market price of the Class A non-voting shares on the last trading day immediately preceding the date of the grant. The term within which the option may be exercised will be ten years. Up to 20% of the shares subject to the option may be purchased on and following each of the first five anniversary dates of the date of the grant and any unexercised option may be carried over to subsequent years. An option will not be assignable and will terminate upon the termination of the employee's employment with the Corporation and its subsidiaries for reasons other than retirement, disability or death. The Toronto Stock Exchange has approved the Stock Option Plan subject to its confirmation by a majority of the votes cast at the Annual and Special Meeting of Shareholders.

Directors of the Corporation who are also employees of the Corporation or its subsidiaries will be eligible for participation in the Stock Option Plan.

ELECTION OF DIRECTORS

The management of the Corporation proposes to nominate, and the persons named in the accompanying form of proxy intend to vote for the election as directors of, the persons whose names are set forth below, all of whom are now directors and have been for the periods indicated. The management of the Corporation does not contemplate that any one of the nominees will be unable to serve as a director. Each director elected will hold office until the close of the next annual meeting of shareholders of the Corporation. Following is information with respect to each proposed nominee for the board of directors.

Names of proposed nominees and all other major positions and offices held with the Corporation	All major positions and offices held with significant affiliates of the Corporation	Principal occupation or employment	Periods served as a director of the Corporation	Approximate number of shares of each class of shares of the Corporation and of ATCO beneficially owned or over which control or direction is exercised
W.L. Britton, Q.C. (1)	Director of Alberta Power Limited and of ATCO (4)	Partner, Bennett Jones (barristers & solicitors)	1980 to date	675 Series H second preferred shares of the Corporation; 3,870 Class I non-voting, 3,935 Class II voting and 400 11½% convertible junior preferred shares of ATCO
G.L. Crawford, Q.C (1) (3)	Director of Canadian Western Natural Gas Company Limited	Associate, McLaws & Company (barristers & solicitors)	1972 to date	285 Class A non-voting and 100 Class B common shares of the Corporation
B.K. French (2)	Director of ATCO (4)	President, Karusel Management Ltd. (property management and management consultants)	1981 to date	350 Class B common shares of the Corporation; 1,900 Class I non-voting and 3,000 Class II voting shares of ATCO
V.L. Horte (1)		President, V.L. Horte Associates Limited (oil, gas and energy consulting firm)	1981 to date	100 Class A non-voting and 100 Class B common shares of the Corporation
W.R. Horton, Executive Vice-President, Utilities (1)	President and Chief Operating Officer and director of Alberta Power Limited, Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited and director of ATCOR Resources Limited	Executive Vice-President, Utilities of the Corporation and President and Chief Operating Officer, Alberta Power Limited, Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited	1984 to date	
H.E. Joudrie (3)		President and Chief Executive Officer, Nu-West Group Limited (house building, land and commercial real estate development and oil and gas company) (6)	1982 to date	

Names of proposed nominees and all other major positions and offices held with the Corporation	All major positions and offices held with significant affiliates of the Corporation	Principal occupation or employment	Periods served as a director of the Corporation	Approximate number of shares of each class of shares of the Corporation and of ATCO beneficially owned or over which control or direction is exercised
E.W. King (2)	Director of ATCO, Alberta Power Limited, Canadian Western Natural Gas Company Limited, Northwestern Utilities Limited and ATCOR Resources Limited	Corporate Director	1968 to date	3,174 Class A non-voting and 3,174 Class B common shares of the Corporation; 3,000 Class I non-voting and 1,000 Class II voting shares of ATCO
R.W.A. Laidlaw (3)		President, Gibson Petroleum Company Limited (marketing and transportation company)	1981 to date	
C.M. Leitch, Q.C. (2)		Partner, MACLEOD DIXON (barristers & solicitors)	1984 to date	
D.R.B. McArthur (2)		Corporate Director	1969 to date	101 Class A non-voting, 101 Class B common, 1,500 Series H and 1,000 Series I second preferred shares of the Corporation
W.S. McGregor		President, Numac Oil & Gas Ltd. (oil, gas and mineral exploration company)	1972 to date	500 Class I non-voting shares of ATCO
C.S. Richardson, Deputy Chairman of the Board (1)	Senior Vice-President, Finance and director of ATCO and director of Alberta Power Limited, Canadian Western Natural Gas Company Limited, Northwestern Utilities Limited and ATCOR Resources Limited (4)	Senior Vice-President, Finance, ATCO (natural resource services, property development and manufacturing company) and Deputy Chairman of the Board of the Corporation	1980 to date	1,000 Class B common, 750 Series H and 200 Series I second preferred shares of the Corporation; 21,400 Class I non-voting, 14,800 Class II voting and 400 11½% convertible junior preferred shares of ATCO
D.M. Ritchie (1)		President, Medway Investments Corporation Ltd. (real estate properties and energy resources management company)	1981 to date	400 Class II voting shares of ATCO
N.W. Robertson (2)	President and Chief Operating Officer and director of ATCO and director of ATCOR Resources Limited (4)	President and Chief Operating Officer, ATCO	1980 to date	3,500 Class A non-voting shares of the Corporation; 11,548 Class I non-voting and 1,600 Class II voting shares of ATCO
R.D. Southern, Chairman of the Board and Chief Executive Officer (1)	Deputy Chairman and Chief Executive Officer and director of ATCO and Chairman of the Board and Chief Executive Officer and director of Alberta Power Limited, Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited and Chairman of the Board and director of ATCOR Resources Limited (4)	Deputy Chairman of the Board and Chief Executive Officer, ATCO and Chairman of the Board and Chief Executive Officer of the Corporation	1977 to 1979 1980 to date	1 Class A non-voting, 18,601 Class B common, 45,000 Series H and 8,000 Series I second preferred shares of the Corporation; 5,186,313 Class I non-voting and 2,812,580 Class II voting shares of ATCO (5)

Names of proposed nominees and all other major positions and offices held with the Corporation	All major positions and offices held with significant affiliates of the Corporation	Principal occupation or employment	Periods served as a director of the Corporation	Approximate number of shares of each class of shares of the Corporation and of ATCO beneficially owned or over which control or direction is exercised
J.D. Wood, President and Chief Operating Officer (1) (3)	Deputy Chairman of the Board and director of Alberta Power Limited, Canadian Western Natural Gas Company Limited, Northwestern Utilities Limited and ATCOR Resources Limited and director of ATCO (4)	President and Chief Operating Officer of the Corporation	1981 to date	1,000 Class II voting shares of ATCO and 35 preferred shares 5½% Series of Canadian Western Natural Gas Company Limited

(1) Member of the Executive Committee
(2) Member of the Audit Committee
(3) Member of the Human Resources Committee
(4) Director or officer of subsidiaries of ATCO
(5) R.D. Southern owns 60% and ADSCO Investments Ltd., a company of which R. D. Southern is the sole common shareholder, owns 40% of the equity shares of Sentgraf Enterprises Ltd. which owns 3,043,552 Class I non-voting shares amd 1,521,776 Class II voting shares of ATCO. ADSCO Investments Ltd. owns 528,406 Class I non-voting shares and 262,624 Class II voting shares of ATCO.The stated shareholdings of R. D. Southern include these shares. R. D. Southern controls ATCO which is the beneficial owner of 13,578,552 Class A non-voting and 13,578,552 Class B common shares of the Corporation.
(6) H.E. Joudrie has resigned his offices with Nu-West Group Limited effective March 31, 1985 and has been appointed President and Chief Executive Officer, Dome Canada Limited effective April 1, 1985.

REMUNERATION OF DIRECTORS AND OFFICERS

The following statement sets forth the aggregate remuneration paid or payable by the Corporation and by each of its subsidiaries in respect of the Corporation's financial year ended December 31, 1984 to the directors in their capacity as directors of the Corporation and its subsidiaries and, separately, to the officers of the Corporation who, in their capacity as officers or employees of the Corporation and its subsidiaries, received aggregate remuneration in excess of $40,000 in that year.

		NATURE OF REMUNERATION		
	Directors' fees	Salaries	Other(1)	Total
REMUNERATION OF DIRECTORS				
(A) Number of directors: 17				
(B) Body corporate incurring the expense:				
Corporation	$139,467			$139,467
Alberta Power Limited	5,500			5,500
Canadian Western Natural Gas Company Limited	5,400			5,400
Northwestern Utilities Limited	2,100			2,100
ATCOR Resources Limited	14,125			14,125
REMUNERATION OF OFFICERS				
(A) Number of officers, of whom 5 are directors: 15				
(B) Body corporate incurring the expense:				
Corporation	22,000	$869,414	$333,804	1,225,218
Alberta Power Limited	10,200	250,366	42,049	302,615
Canadian Western Natural Gas Company Limited	8,100	250,366	42,049	300,515
Northwestern Utilities Limited	11,400	250,366	42,049	303,815
ATCOR Resources Limited	24,450			24,450
TOTALS	$242,742	$1,620,512	$459,951	$2,323,205

(1) This represents the estimated aggregate cost to the Corporation and its subsidiaries in the Corporation's financial year ended December 31, 1984 of all benefits proposed to be paid under any pension or retirement plan upon retirement at normal retirement age. The only pension or retirement benefits payable to the directors of the Corporation are payable to directors who are or have been officers of the Corporation.

The Corporation, ATCO and their affiliates have purchased insurance with an annual aggregate limit of $25,000,000 for such corporations and for their directors and officers. The approximate amount of premium paid by the Corporation in the financial year ended December 31, 1984 in respect of directors of the Corporation as a group was $705 and in respect of the officers of the Corporation as a group was $590. No part of the premium was paid by any director or officer. The Corporation is responsible for the first $50,000 on any loss and $2,500 is deductible in respect of claims against each director or officer to a maximum of $7,500.

Subject to the confirmation by the shareholders of the establishment of the Stock Option Plan at the Annual and Special Meeting of Shareholders and pursuant to its terms (reference is made to "Stock Option Plan"), the Corporation granted on February 25, 1985 options to purchase 445,000 Class A non-voting shares to five officers of the Corporation (of whom four are also directors) and options to purchase 110,000 Class A non-voting shares to five officers of subsidiaries of the Corporation. The Class A non-voting shares subject to the options may be purchased at the price of $16.75 per share on or before February 25, 1995. The price range of the Class A non-voting shares of the Corporation for the 30 days prior to February 25, 1985 was $16.50 to $17.25.

APPOINTMENT OF AUDITOR

The persons named in the accompanying form of proxy intend to vote for the appointment of Price Waterhouse as the auditor of the Corporation to hold office until the next annual meeting of shareholders of the Corporation. Price Waterhouse was first appointed in 1981.

AMENDMENTS TO BY-LAW NO. 1

The board of directors of the Corporation has resolved to amend certain sections of By-Law No. 1, the by-law relating generally to the transaction of the business and affairs of the Corporation. The text of the directors' resolution setting out the amendments is reproduced as Exhibit "A" to this Management Proxy Circular.

Briefly summarized, the effects of the amendments which the shareholders will be asked to confirm by a majority of votes cast at the Annual and Special Meeting are minor corrections to sections 1.01, 3.01, 4.01, 4.03, 4.07, 6.04, 9.01, 10.05, 10.06, 10.10, 10.11, and 10.12 of By-law No. 1.

GENERAL

The contents and the sending of this Management Proxy Circular have been approved by the directors of the Corporation.

DATED at Edmonton, Alberta, this 15th day of March, 1985.

A. M. Anderson

A.M. Anderson,
Secretary

EXHIBIT "A"
DIRECTORS' RESOLUTION AMENDING BY-LAW NO. 1 OF THE CORPORATION

EXHIBIT "A"
DIRECTORS' RESOLUTION AMENDING BY-LAW NO. 1
OF THE CORPORATION

RESOLVED THAT By-Law No. 1 of the Corporation is amended as follows:

a) section 1.01 is amended by deleting the following definitions:
"articles"
"Corporation"

b) sub-section 3.01 (d) is amended by deleting the word "charge" such that sub-section 3.01 (d) shall read as follows:

"3.01 BORROWING POWER - Without limiting the borrowing powers of the Corporation as set forth in the Act, the board may:

(d) mortgage, hypothecate, pledge or otherwise create a security interest in all or any property of the Corporation, owned or subsequently acquired, to secure any obligation of the Corporation."

c) section 4.01 is amended by deleting the first sentence and substituting therefor words such that section 4.01 shall read as follows:

"4.01 NUMBER OF DIRECTORS AND QUORUM - The Board shall consist of not fewer than the minimum and not more than the maximum number of directors fixed from time to time by the articles of the Corporation. Subject to section 4.09, the quorum for the transaction of business at any meeting of the board shall consist of five directors or such greater number as the board may from time to time determine."

d) section 4.03 is amended by adding the words "Subject to the provisions of the Act," before the words "The election shall be by ordinary resolution." such that section 4.03 shall read as follows:

"4.03 ELECTION AND TERM - The election of directors shall take place at each annual meeting of shareholders and all the directors then in office shall retire but, if qualified, shall be eligible for re-election. The number of directors to be elected at any such meeting shall, if a maximum and minimum number of directors is authorized, be the number of directors then in office unless the directors or the shareholders otherwise determine or shall, if a fixed number of directors is authorized, be such fixed number. Subject to the provisions of the Act, the election shall be by ordinary resolution. If an election of directors is not held at the proper time, the incumbent directors shall continue in office until their successors are elected."

e) section 4.07 is amended by adding the words "provisions of the" before the word "Act" such that section 4.07 shall read as follows:

"4.07 VACANCIES - Subject to the provisions of the Act, a quorum of the board may fill a vacancy in the board, except a vacancy resulting from an increase in the minimum number of directors or from a failure of the shareholders to elect the minimum number of directors. In the absence of a quorum of the board, or if the vacancy has arisen from a failure of the shareholders to elect the minimum number of directors, the board shall forthwith call a special meeting of shareholders to fill the vacancy. If the board fails to call such meeting or if there are no directors then in office, any shareholder may call the meeting."

f) section 6.04 is amended by adding the word "the" before the word "auditor" such that section 6.04 shall read as follows:

"6.04 SECRETARY - The secretary shall attend and be the secretary of all meetings of the board and of shareholders and, where practicable, of committees of the board and shall enter or cause to be entered in records kept for that purpose minutes of all proceedings at such meetings; he shall give or cause to be given as and when instructed all notices to shareholders, directors, officers, the auditor and members of committees of the board; he shall be the custodian of the stamp or mechanical device generally used for affixing the corporate seal of the Corporation and all books, papers, records, documents and instruments belonging to the Corporation, except when some other officer or agent has been appointed for that purpose."

g) section 9.01 is amended by deleting the sentence, "Dividends may be paid in money or property or by issuing fully paid shares of the Corporation." and by substituting therefor the sentence "The Corporation may pay a dividend by issuing fully paid shares of the Corporation and, subject to the provisions of the Act, the Corporation may pay a dividend in money or property." such that section 9.01 shall read as follows:

"9.01 DIVIDENDS - Subject to the provisions of the Act, the board may declare dividends payable to the shareholders according to their respective rights and interest in the Corporation. The Corporation may pay a dividend by issuing fully paid shares of the Corporation and, subject to the provisions of the Act, the Corporation may pay a dividend in money or property."

h) sections 10.05 and 10.06 are amended by adding the words "last business" before the words "day immediately preceding" such that sections 10.05 and 10.06 shall read as follows:

"10.05 LIST OF SHAREHOLDERS ENTITLED TO NOTICE - For every meeting of shareholders, the Corporation shall prepare a list of shareholders entitled to receive notice of the meeting, arranged in alphabetical order and showing the number of shares held by each shareholder entitled to vote at the meeting. If a record date for the meeting is fixed pursuant to section 10.06, the shareholders listed shall be those registered at the close of business on such record date. If no record date is fixed, the shareholders listed shall be those registered at the close of business on the last business day immediately preceding the day on which notice of the meeting is given. The list shall be available for examination by any shareholder during usual business hours at the registered office of the Corporation or at the place where the central securities register is maintained and at the meeting for which the list was prepared. For the purposes of this section 10.05, the names of persons appearing in the securities register at the requisite time as the holder of one or more shares carrying the right to vote at such meeting shall be deemed to be a list of shareholders.

"10.06 RECORD DATE FOR NOTICE - The board may fix in advance a date, preceding the date of any meeting of shareholders by not more than 50 days and not less than 21 days, as a record date for the determination of the shareholders entitled to notice of the meeting, and notice of any such record date shall be given not less than 7 days before such record date, by newspaper advertisement and otherwise in the manner provided in the Act. If no record date is so fixed, the record date for the determination of the shareholders entitled to notice of the meeting shall be at the close of business on the last business day immediately preceding the day on which the notice is given."

i) section 10.10 is amended by adding the words "the ownership of" after the word "transferred" such that section 10.10 shall read as follows:

"10.10 RIGHT TO VOTE - Subject to the provisions of the Act as to authorized representatives of any other body corporate or association, at any meeting of shareholders for which the Corporation has prepared the list referred to in section 10.05, every person who is named in such list shall be entitled to vote the shares shown opposite his name except to the extent that, where the Corporation has fixed a record date in respect of such meeting pursuant to section 10.06, such person has transferred the ownership of any of his shares after such record date and the transferee, having produced properly endorsed certificates evidencing such shares or having otherwise established that he owns such shares, has demanded not later than 10 days before the meeting that his name be included in such list. In any such case the transferee shall be entitled to vote the transferred shares at the meeting."

j) section 10.11 is amended by deleting all of the present wording and substituting therefor words such that section 10.11 shall read as follows:

"10.11 PROXIES - Every shareholder entitled to vote at a meeting of shareholders may by means of a proxy appoint a proxyholder and one or more alternate proxyholders, who need not be shareholders, to attend and act at the meeting in the manner and to the extent authorized and with the authority conferred by the proxy. A proxy shall be executed by the shareholder or his attorney authorized in writing and shall conform with the requirements of the Act."

k) section 10.12 is amended by deleting the word "unless" before the words "it has been received" and by deleting the first sentence and substituting therefor words such that section 10.12 shall read as follows:

"10.12 TIME FOR DEPOSIT OF PROXIES - The board may specify in a notice calling a meeting of shareholders a time not exceeding 48 hours, excluding non-business days, preceding the meeting or an adjournment of the meeting before which time proxies to be used at the meeting must be deposited with the Corporation or its agent. A proxy shall be acted upon only if, prior to the time so specified, it shall have been deposited with the Corporation or its agent specified in such notice or, if no such time is specified, it has been received by the secretary of the Corporation or by the chairman of the meeting or any adjourned meeting prior to the time of voting."